Federal Register

Friday,
July 20, 2007

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM04–7–000; Order No. 697]

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities

Issued June 21, 2007.

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal Regulations governing market-based rates for public utilities pursuant to the Federal Power Act (FPA). The Commission is codifying and, in certain respects, revising its current standards for market-based rates for sales of electric energy, capacity, and ancillary services. The Commission is retaining several of the core elements of its current standards for granting market-based rates and revising them in certain respects. The Commission also adopts a number of reforms to streamline the administration of the market-based rate program.

DATES: *Effective Date:* This rule will become effective September 18, 2007.

FOR FURTHER INFORMATION CONTACT:

Debra A. Dalton (Technical Information), Office of Energy Markets and Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6253.

Elizabeth Arnold (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8818.

SUPPLEMENTARY INFORMATION:

TABLE OF CONTENTS

	Paragraph Nos.
I. Introduction	1
II. Background	7
III. Overview of Final Rule	12
IV. Discussion	33
A. Horizontal Market Power	33
1. Whether to Retain the Indicative Screens	33
2. Indicative Market Share Screen Threshold Levels and Pivotal Supplier Application Period	80
a. Market Share Threshold	82
b. Pivotal Supplier Application Period	94
3. DPT Criteria	96
4. Other Products and Models	118
5. Native Load Deduction	125
a. Market Share Indicative Screen	125
b. Pivotal Supplier Indicative Screen	143
c. Clarification of Definition of Native Load	150
d. Other Native Load Concerns	153
6. Control and Commitment	156
a. Presumption of Control	164
b. Requirement for Sellers to have a Rate on File	212
7. Relevant Geographic Market	215
a. Default Relevant Geographic Market	215
b. NERC's Balancing Authority Area and Default Geographic Area	247
c. Additional Guidelines for Alternative Geographic Market and Flexibility	253
d. Specific Issues Related to Power Pools and SPP	279
e. RTO/ISO Exemption	285
8. Use of Historical Data	292
9. Reporting Format	302
10. Exemption for New Generation (Formerly Section 35.27(a) of the Commission's Regulations)	307
a. Elimination of Exemption in Section 35.27(a)	307
b. Grandfathering	327
c. Creation of a Safe Harbor	335
11. Nameplate Capacity	339
12. Transmission Imports	346
a. Use of Historical Conditions and OASIS Practices	348
b. Use of Total Transfer Capability (TTC)	363
c. Accounting for Transmission Reservations	365
d. Allocation of Transmission Imports based on Pro Rata Shares of Seller's Uncommitted Generation Capacity	370
e. Miscellaneous Comments	376
f. Required SIL Study for DPT Analysis	382
13. Procedural Issues	387
B. Vertical Market Power	397
1. Transmission Market Power	400
a. OATT Requirement	403
b. OATT Violations and MBR Revocation	411
c. Revocation of Affiliates' MBR Authority	422
2. Other Barriers to Entry	428
3. Barriers Erected or Controlled by Other Than The Seller	452
4. Planning and Expansion Efforts	454
5. Monopsony Power	459
C. Affiliate Abuse	464
1. General Affiliate Terms and Conditions	464

TABLE OF CONTENTS—Continued

	Paragraph Nos.
a. Codifying Affiliate Restrictions in Commission Regulations	464
b. Definition of ''Captive Customers''	469
c. Definition of ''Non-Regulated Power Sales Affiliate''	484
d. Other Definitions	496
e. Treating Merging Companies as Affiliates	499
f. Treating Energy/Asset Managers as Affiliates	503
g. Cooperatives	518
2. Power Sales Restrictions	529
3. Market-Based Rate Affiliate Restrictions (formerly Code of Conduct) for Affiliate Transactions Involving Power Sales and Brokering, Non-Power Goods and Services and Information Sharing	544
a. Uniform Code of Conduct/Affiliate Restrictions—Generally	546
b. Exceptions to the Independent Functioning Requirement	553
c. Information Sharing Restrictions	570
d. Definition of ''Market Information''	590
e. Sales of Non-Power Goods or Services	595
f. Service Companies or Parent Companies Acting on Behalf of and for the Benefit of a Franchised Public Utility	599
D. Mitigation	604
1. Cost-Based Rate Methodology	606
a. Sales of One Week or Less	606
b. Sales of more than one week but less than one year	632
c. Sales of one year or greater	658
d. Alternative methods of mitigation	660
2. Discounting	699
3. Protecting Mitigated Markets	720
a. Must Offer	720
b. First-Tier Markets	776
c. Sales that Sink in Unmitigated Markets	794
d. Proposed Tariff Language	825
E. Implementation Process	832
1. Category 1 and 2 Sellers	836
a. Establishment of Category 1 and 2 Sellers	836
b. Threshold for Category 1 Sellers and Other Proposed Modifications	845
2. Regional Review and Schedule	869
F. MBR Tariff	897
1. Tariff of General Applicability	901
2. Placement of Terms and Conditions	925
3. Single Corporate Tariff	928
G. Legal Authority	938
1. Whether Market-Based Rates Can Satisfy the Just and Reasonable Standard Under the FPA	938
Consistency of Market-based Rate Program with FPA Filing Requirements	956
2. Whether Existing Tariffs Must Be Found to Be Unjust and Unreasonable, and Whether the Commission Must Establish a Refund Effective Date	972
H. Miscellaneous	975
1. Waivers	975
a. Accounting Waivers	979
b. Timing	988
c. Part 34 Waivers Blanket Authorizations	993
2. Sellers Affiliated with a Foreign Utility	1000
3. Change in Status	1008
a. Fuel Supplies	1011
b. Transmission Outages	1019
c. Control	1027
d. Triggering Events	1033
e. Timing of Reporting	1035
f. Sellers Affiliated with a Foreign Utility	1040
4. Third-Party Providers of Ancillary Services	1046
a. Internet Postings and Reporting Requirements	1052
b. Pricing for Ancillary Services in RTOs/ISOs	1062
5. Reactive Power and Real Power Losses	1072
a. Reactive Power	1073
b. Real Power Losses	1075
V. Section-by-Section Analysis of Regulations	1077
VI. Information Collection Statement	1105
VII. Environmental Analysis	1124
VIII. Regulatory Flexibility Act	1125
IX. Document Availability	1129
X. Effective Date and Congressional Notification	1132
Regulatory Text	
Appendix A to Subpart H: Standard Screen Format	
Appendix B to Subpart H: Corporate Entities and Assets sample appendix	
Appendix C to the Final Rule: Required Provisions of the Market-Based Rate Tariff	

TABLE OF CONTENTS—Continued

Paragraph Nos.

Appendix D to the Final Rule: Regions and Schedule for Regional Market power Update Process
Appendix E to the Final Rule: List of Commenters and Acronyms
Attachment A to the Final Rule: MOELLER, Commissioner, dissenting in part

Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

I. Introduction

1. On May 19, 2006, the Commission issued a Notice of Proposed Rulemaking (NOPR), pursuant to sections 205 and 206 of the Federal Power Act (FPA),[1] in which the Commission proposed to amend its regulations governing market-based rate authorizations for wholesale sales of electric energy, capacity and ancillary services by public utilities. In the NOPR, the Commission proposed to modify all existing market-based authorizations and tariffs so they would reflect any new requirements ultimately adopted in the Final Rule. After considering the comments received in response to the NOPR, the Commission adopts in many respects the proposals contained in the NOPR, but with a number of modifications.

2. This Final Rule represents a major step in the Commission's efforts to clarify and codify its market-based rate policy by providing a rigorous up-front analysis of whether market-based rates should be granted, including protective conditions and ongoing filing requirements in all market-based rate authorizations, and reinforcing its ongoing oversight of market-based rates. The specific components of this rule, in conjunction with other regulatory activities, are designed to ensure that market-based rates charged by public utilities are just and reasonable. There are three major aspects of the Commission's market-based rate regulatory regime.

3. First is the analysis that is the subject of this rule: whether a market-based rate seller or any of its affiliates has market power in generation or transmission and, if so, whether such market power has been mitigated.[2] If the seller is granted market-based rates, the authorization is conditioned on: affiliate restrictions governing transactions and conduct between power sales affiliates where one or more of those affiliates has captive customers; a requirement to file post-transaction electric quarterly reports (EQRs) containing specific information about contracts and transactions; a requirement to file any change of status; and a requirement for all large sellers to file triennial updates.[3]

4. Second, for wholesale sellers that have market-based rate authority and sell into day ahead or real-time organized markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), they do so subject to specific RTO/ISO market rules approved by the Commission and applicable to all market participants. These rules are designed to help ensure that market power cannot be exercised in those organized markets and include additional protections (*e.g.*, mitigation measures) where appropriate to ensure that prices in those markets are just and reasonable. Thus, a seller in such markets not only must have an authorization based on an analysis of that individual seller's market power, but it must also abide by additional rules contained in the RTO/ISO tariffs.

5. Third, the Commission, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates. For example, based on its review of triennial market power updates required of market-based rate sellers, its review of EQR filings made by market-based rate sellers, and its review of required notices of change in status, the Commission may institute a section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission may also, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty paid to the United States Treasury if a seller is found to have engaged in prohibited market manipulation or to have violated Commission orders, tariffs or rules.

6. The Commission recognizes that several recent court decisions by the United States Court of Appeals for the Ninth Circuit[4] have created some uncertainty for sellers transacting pursuant to our market-based rate program. The cases raise issues with respect to the circumstances under which sellers' pre-authorized market-based rate sales may be subject to retroactive refunds and the circumstances under which buyers might be able to invalidate or modify contracts based on the argument that the contracts were entered into at a time when markets were dysfunctional. The Commission's first and foremost duty is to protect customers from unjust and unreasonable rates; however, we recognize that uncertainties regarding rate stability and contract sanctity can have a chilling effect on investments and a seller's willingness to enter into long-term contracts and this, in turn, can harm customers in the long run. The Commission recently provided guidance in this regard, noting that these Ninth Circuit decisions addressed a unique set of facts and a market-based rate program that has undergone substantial improvement since 2001, and reiterating that an *ex ante* finding of the absence of market power, coupled with the EQR filing and effective regulatory oversight qualifies as sufficient prior review for market-based rate contracts to satisfy the notice and filing requirements of FPA section 205.[5] Through this Final Rule, the Commission is clarifying and further

[1] 16 U.S.C. 824d, 824e.

[2] The Commission also considers whether the seller or its affiliates can erect other barriers to entry (*e.g.*, key sites for building new power supply; key inputs to power supply) in the relevant market and whether there is evidence of affiliate abuse or reciprocal dealing.

[3] During the past three years, the Commission has initiated over 20 investigations under section 206 of the FPA because of concerns of possible market power. Several of those investigations led to the revocation or voluntary relinquishing of market-based rate authority and the ordering of refunds by sellers.

[4] *See State of California, ex rel. Bill Lockyer* v. *FERC*, 383 F.3d 1006 (9th Cir. 2004), *cert. denied* (S. Ct. Nos. 06–888 and 06–1100, June 18, 2007) (*Lockyer*); *Public Utility District No. 1 of Snohomish County, Washington* v. *FERC*, 471 F.3d 1053 (9th Cir. 2006) (*Snohomish*); *Public Utilities Commission of the State of California and California Electric Oversight Board* v. *FERC*, 474 F.3d 587 (9th Cir. 2007) (*California Commission*).

[5] *CAlifornians for Renewable Energy, Inc.* v. *Cal. Pub. Util. Com'n*, 119 FERC ¶ 61,058 (2007).

improving its market-based rate program. Moreover, the Commission will explore ways to continue to improve its market-based rate program and processes to assure appropriate customer protections but at the same time provide greater regulatory and market certainty for sellers in light of the above court opinions.

II. Background

7. In 1988, the Commission began considering proposals for market-based pricing of wholesale power sales. The Commission acted on market-based rate proposals filed by various wholesale suppliers on a case-by-case basis. Over the years, the Commission developed a four-prong analysis used to assess whether a seller should be granted market-based rate authority: (1) Whether the seller and its affiliates lack, or have adequately mitigated, market power in generation; (2) whether the seller and its affiliates lack, or have adequately mitigated, market power in transmission; (3) whether the seller or its affiliates can erect other barriers to entry; and (4) whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.

8. The Commission initiated the instant rulemaking proceeding in April 2004 to consider ''the adequacy of the current analysis and whether and how it should be modified to assure that prices for electric power being sold under market-based rates are just and reasonable under the Federal Power Act.'' [6] At that time, the Commission noted that much has changed in the industry since the four-prong analysis was first developed and posed a number of questions that would be explored through a series of technical conferences.

9. On April 14, 2004, the Commission issued an order modifying the then-existing generation market power analysis and its policy governing market power mitigation, on an interim basis.[7] The April 14 Order adopted a policy that provided sellers a number of procedural options, including two indicative generation market power screens (an uncommitted pivotal supplier analysis and an uncommitted market share analysis), and the option of proposing mitigation tailored to the particular circumstances of the seller that would eliminate the ability to exercise market power. The order also explained that sellers could choose to adopt cost-based rates. On July 8, 2004, the Commission addressed requests for rehearing of the April 14 Order, reaffirming the basic analysis, but clarifying and modifying certain instructions for performing the generation market power analysis. Over the next year, the Commission convened four technical conferences, seeking input regarding all four prongs of the analysis.

10. On May 19, 2006, the Commission issued a NOPR in this proceeding.[8] The Commission explained that refining and codifying effective standards for market-based rates would help customers by ensuring that they are protected from the exercise of market power and would also provide greater certainty to sellers seeking market-based rate authority.

11. The regulations proposed in the NOPR adopted in most respects the Commission's existing standards for granting market-based rates, and proposed to streamline certain aspects of its filing requirements to reduce the administrative burdens on sellers, customers and the Commission. The Commission received over 100 comments and reply comments in response to the NOPR. A list of commenters is attached as Appendix E.

III. Overview of Final Rule

12. In this Final Rule, the Commission revises and codifies in the Commission's regulations the standards for market-based rates for wholesale sales of electric energy, capacity and ancillary services. The Commission also adopts a number of reforms to streamline the administration of the market-based rate program. As set forth below, the Final Rule adopts in many respects the proposals contained in the NOPR, but with a number of modifications.

Horizontal Market Power

13. In this Final Rule, the Commission adopts, with certain modifications, two indicative market power screens (the uncommitted market share screen (with a 20 percent threshold) and the uncommitted pivotal supplier screen), each of which will serve as a cross check on the other to determine whether sellers may have market power and should be further examined. Sellers that fail either screen will be rebuttably presumed to have market power. However, such sellers will have full opportunity to present evidence (through the submission of a Delivered Price Test (DPT) analysis) demonstrating that, despite a screen failure, they do not have market power, and the Commission will continue to weigh both available economic capacity and economic capacity when analyzing market shares and Hirschman-Herfindahl Indices (HHIs).

14. With regard to control over generation capacity, the Commission finds that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. No single factor or factors necessarily results in control. The Commission will require a seller to make an affirmative statement as to whether a contractual arrangement (energy management agreement, tolling agreement, specific contractual terms, etc.) transfers control and to identify the party or parties it believes controls the generation facility. Regarding a presumption of control, the Commission will continue its practice of attributing control to the owner absent a contractual agreement transferring such control, and we provide guidance as to how we will consider jointly-owned facilities.

15. The Commission adopts its current approach with regard to the default relevant geographic market, with some modifications. In particular, the Commission will continue to use a seller's control area (balancing authority area) [9] or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis. The Commission also provides guidance as to the factors the Commission will consider in evaluating whether, in a particular case, to adopt an alternative geographic market instead of relying on the default geographic market.

16. The Commission modifies the native load proxy for the market share screens from the minimum peak day in the season to the average peak native load, averaged across all days in the season, and clarifies that native load can only include load attributable to native load customers based on the definition of native load commitment in § 33.3(d)(4)(i) of the Commission's regulations. In addition, sellers are

[6] *Market-Based Rates for Public Utilities*, 107 FERC ¶ 61,019 AT P 1(2004) (initiating rulemaking proceeding).

[7] *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018 (April 14 Order), *order on reh'g*, 108 FERC ¶ 61,026 (2004) (July 8 Order).

[8] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Notice of Proposed Rulemaking, 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 (2006) (NOPR).

[9] As discussed below in the Horizontal Market Power section, the Commission adopts the use of balancing authority area instead of control area.

given the option of using seasonal capacity instead of nameplate capacity.

17. The Commission retains the snapshot in time approach based on historical data for both the indicative screens and the DPT analysis and disallows projections to that data. A standard reporting format is adopted for sellers to follow when summarizing their analysis.

18. The Commission modifies the treatment of newly constructed generation and adopts an approach that requires all sellers to perform a horizontal analysis for the grant of market-based rate authority.

19. With regard to simultaneous transmission import limit studies (SILs), the Commission adopts the requirement that the SIL study be used as a basis for transmission access for both the indicative screens and the DPT analysis. Further, the Commission clarifies that the SIL study as shown in Appendix E of the April 14 Order is the only study that meets our requirements. The Commission provides guidance regarding how to perform the SIL study, including accounting for specific OASIS practices.

20. Finally, the Commission adopts procedures under which intervenors in section 205 proceedings may obtain expedited access to Critical Energy Infrastructure Information (CEII) or other information for which privileged treatment is sought.

Vertical Market Power

21. With regard to vertical market power and, in particular, transmission market power, the Commission continues the current policy under which an open access transmission tariff (OATT) is deemed to mitigate a seller's transmission market power. However, in recognition of the fact that OATT violations may nonetheless occur, the Commission states that a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority may subject the seller to revocation of its market-based rate authority or other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties. In addition, the Commission creates a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation.

22. With regard to other barriers to entry, the Commission adopts the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but modifies the requirements when addressing other barriers to entry. The Commission also provides clarification regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry). The Commission adopts a rebuttable presumption that ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars do not allow a seller to raise entry barriers, but intervenors are allowed to demonstrate otherwise. The Final Rule also requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars. The Commission will require sellers to provide this description and to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. The Final Rule clarifies that the obligation in this regard applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.

Affiliate Abuse

23. With regard to affiliate abuse, the Commission adopts the NOPR proposal to discontinue considering affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead to codify affiliate restrictions in the Commission's regulations and address affiliate abuse by requiring that the provisions provided in the affiliate restrictions be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. As codified in this Final Rule, the affiliate restrictions include a provision prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates[10] without first receiving Commission authorization for the transaction under section 205 of the FPA. The Commission also codifies as part of the affiliate restrictions the requirements that previously have been known as the market-based rate ''code of conduct'' (governing the separation of functions, the sharing of market information, sales of non-power goods or services, and power brokering), as clarified and modified in this Final Rule. The Commission modifies certain of these provisions, including separation of functions and information sharing, consistent with certain requirements and exceptions contained in the Commission's standards of conduct.[11] In the Final Rule the Commission defines ''captive customers'' as ''any wholesale or retail electric energy customers served under cost-based regulation'' and provides clarification that the definition of ''captive customers'' does not include those customers who have retail choice, *i.e.*, the ability to select a retail supplier based on the rates, terms and conditions of service offered. In addition, among other clarifications, the Commission clarifies and modifies the definition of ''non-regulated power sales affiliate,'' and changes the term to ''market-regulated power sales affiliate.''

24. The Commission also provides clarification as to what types of affiliate transactions are permissible and the criteria used to make those decisions, and how the Commission will treat merging partners. In addition, the Commission codifies in the regulations a prohibition on the use of third-party entities, including energy/asset managers, to circumvent the affiliate restrictions, but does not adopt the NOPR proposal to treat energy/asset managers as affiliates. The Commission also provides clarification regarding the Commission's market-based rate policies as they relate to cooperatives.

Mitigation

25. With regard to mitigation, in the Final Rule the Commission retains the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less; the default mitigation rate for mid-term sales (sales of more than one week but less than one year) priced at an embedded cost ''up to'' rate reflecting the costs of the unit(s) expected to provide the service; and the existing policy for sales of one year or more (long-term) sales.[12] The

[10] In the NOPR, the Commission proposed to define the term ''non-regulated power sales affiliate.'' As discussed below, this Final Rule uses the term ''market-regulated power sales affiliate'' instead.

[11] 18 CFR part 358.

[12] We note here that we expect mitigated sellers adopting the default cost-based rates or proposing new cost-based rates will propose a cost-based rate tariff of general applicability for sales of less than one year, and sales of power for one year or longer will be filed with the Commission on a stand-alone basis.

Commission will continue to allow sellers to propose alternative cost-based methods of mitigation tailored to their particular circumstances. The Final Rule also states that the Commission will make its stacking methodology available for the public.[13] In addition, the Commission will continue the practice of allowing discounting and will permit selective discounting by mitigated sellers provided that the sellers do not use such discounting to unduly discriminate or give undue preference.

26. The Commission concludes that use of the Western Systems Power Pool (WSPP) Agreement may be unjust, unreasonable or unduly discriminatory or preferential for certain sellers. Therefore, in an order being issued concurrently with this Final Rule, the Commission is instituting a proceeding under section 206 of the FPA to investigate whether, for sellers found to have market power or presumed to have market power in a particular market, the WSPP Agreement rate for coordination energy sales is just and reasonable in such market.

27. The Commission does not impose an across-the-board ''must offer'' requirement for mitigated sellers. While wholesale customer commenters have raised concerns relating to their ability to access needed power, the Commission concludes that there is insufficient record evidence to support instituting a generic ''must offer'' requirement.

28. The Commission limits mitigation to the market in which the seller has been found to possess, or chosen not to rebut the presumption of, market power and does not place limitations on a mitigated seller's ability to sell at market-based rates in areas in which the seller has not been found to have market power.

29. Finally, regarding mitigation, the Final Rule allows mitigated sellers to make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority under the conditions set forth herein, including a record retention requirement, and provides a tariff provision to allow for such sales.

Implementation Process

30. The Commission adopts the NOPR proposal to create a category of sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses, with certain clarifications and modifications. In addition, the Commission adopts the NOPR proposal to implement a regional approach to updated market power analyses, but reduces the number of regions from nine to six.

31. As for a standardized tariff, the Commission does not adopt the NOPR proposal to adopt a market-based rate tariff of general applicability that all market-based rate sellers will be required to file as a condition of market-based rate authority and to require each corporate family to have only one tariff, with all affiliates with market-based rate authority separately identified in the tariff. Instead, the Commission adopts specific market-based rate tariff provisions that the Commission will require to be part of a seller's market-based rate tariff. However, the Commission will allow a seller to include seller specific terms and conditions in its market-based rate tariff, but the Commission will not review any of these provisions, as they are presumed to be just and reasonable based on the Commission's finding that the seller and its affiliates lack or have adequately mitigated market power in the relevant market.

Miscellaneous Issues

32. The Commission also provides clarifications in the Final Rule with regard to accounting waivers, Part 34 blanket authorizations, sellers affiliated with foreign entities, and the change in status reporting requirement. Further, the Commission abandons the posting requirements for third party sellers of ancillary services at market-based rates as redundant of other reporting requirements.

IV. Discussion

A. Horizontal Market Power

1. Whether To Retain the Indicative Screens

33. As discussed in detail below, the Commission is adopting in this Final Rule two indicative horizontal market power screens, each of which will serve as a cross-check on the other to determine whether sellers may have market power and should be further examined. Although some sellers disagree with the use of two screens or find flaws in them, we conclude that this conservative approach will allow the Commission to more readily identify potential market power. Sellers that fail either screen will be rebuttably presumed to have market power. However, such sellers will have full opportunity to present evidence (through the submission of a DPT analysis) demonstrating that, despite a screen failure, they do not have market power. No screen is perfect, but we believe this approach appropriately balances the need to protect against market power with the desire not to place unnecessary filing burdens on utilities.

34. The first screen is the wholesale market share screen, which measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market.[14]

35. The second screen is the pivotal supplier screen, which evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the balancing authority area's annual peak demand. This screen focuses on the seller's ability to exercise market power unilaterally. It examines whether the market demand can be met absent the seller during peak times. A seller is pivotal if demand cannot be met without some contribution of supply by the seller or its affiliates.[15]

36. Use of the two screens together enables the Commission to measure market power at both peak and off-peak times, and to examine the seller's ability to exercise market power unilaterally and in coordinated interaction with other sellers. Use of the two screens, therefore, provides a more complete picture of a seller's ability to exercise market power.[16]

37. As discussed more fully in the following sections, with regard to determining the total supply in the relevant market, the horizontal market power analysis centers on and examines the balancing authority area where the seller's generation is physically located. Total supply is determined by adding the total amount of uncommitted capacity located in the relevant market (including capacity owned by the seller and competing suppliers) with that of uncommitted supplies that can be imported (limited by simultaneous transmission import capability) into the relevant market from the first-tier markets.

38. Uncommitted capacity is determined by adding the total nameplate or seasonal capacity[17] of

[13] This is addressed in the Mitigation section discussion concerning the cost-based rate methodology for sales of more than one week but less than one year.

[14] April 14 Order, 107 FERC ¶ 61,018 at P 100.

[15] *Id.* at P 72.

[16] *Id.*

[17] As discussed more fully below, in this Final Rule, the Commission gives sellers the option of using seasonal capacity instead of nameplate capacity.

generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales.[18] Uncommitted capacity from a seller's remote generation (generation located in an adjoining balancing authority area) should be included in the seller's total uncommitted capacity amounts. Any simultaneous transmission import capability should first be allocated to the seller's uncommitted remote generation. Any remaining simultaneous transmission import capability would then be allocated to any uncommitted competing supplies.

39. Capacity reductions as a result of operating reserve requirements should be no higher than State and Regional Reliability Council operating requirements for reliability (*i.e.*, operating reserves). Any proposed amounts that are higher than such requirements must be fully supported and will be considered on a case-by-case basis. Moreover, if an intervenor provides conclusive evidence that a seller did not in actual practice comply with the NERC or regional reliability council operating reserve requirements, then we will take this into account in determining the amount of the operating reserve deduction. However, we emphasize that we expect each utility to meet its NERC and regional reliability council reserve requirements, and that absent a clear showing to the contrary by an intervenor, the required operating reserve requirement is what we will use as the deduction in the market-based rate calculation.[19]

40. The Commission does not expect that sellers will have planned generation outages scheduled for the annual peak load day. However, on a case-by-case basis, the Commission will consider credible evidence that planned generation outages for the peak load day of the year should be included based on the particular circumstances of the seller.[20]

41. With regard to the pivotal supplier analysis, after computing the total uncommitted supply available to serve the relevant market, the next step in this analysis involves identifying the wholesale market. The proxy for the wholesale load is the annual peak load (needle peak) less the proxy for native load obligation (*i.e.*, the average of the daily native load peaks during the month in which the annual peak load day occurs). Peak load is the largest electric power requirement (based on net energy for load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts, for the native load and firm wholesale requirements sales.

42. To calculate the net uncommitted supply available to compete at wholesale, the pivotal supplier analysis deducts the wholesale load from the total uncommitted supply. If the seller's uncommitted capacity is less than the net uncommitted supply, the seller satisfies the pivotal supplier portion of the generation market power analysis and passes the screen. If the seller's uncommitted capacity is equal to or greater than the net uncommitted supply, then the seller fails the pivotal supplier analysis which creates a rebuttable presumption of market power.

43. With regard to the wholesale market share analysis, which measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market, uncommitted capacity amounts are used, as described above, with the following variation. Planned outages (that were done in accordance with good utility practice) for each season will be considered. Planned outage amounts should be consistent with those as reported in FERC Form No. 714. To determine the amount of planned outages for a given season, the total number of MW-days of outages is divided by the total number of days in the season. For example, if 500 MW of generation that is out for six days during the winter period the calculation of planned outages would be: (500 MW × 6)/91 or 33 MW.

44. The market share analysis adopts an initial threshold of 20 percent. That is, a seller who has less than a 20 percent market share in the relevant market for all seasons will be considered to satisfy the market share analysis.[21] A seller with a market share of 20 percent or more in the relevant market for any season will have a rebuttable presumption of market power but can present historical evidence to show that the seller satisfies our generation market power concerns.

Commission Proposal

45. In the NOPR, the Commission proposed to retain the indicative screens (pivotal supplier and market share) to assess horizontal market power that were initially adopted in April 2004.[22] Because the indicative screens are intended only to identify the sellers that require further review, the Commission proposed to retain the 20 percent threshold for the wholesale market share indicative screen, stating that the 20 percent market share threshold strikes the right balance in seeking to avoid both ''false negatives'' and ''false positives.'' The Commission also proposed to continue to measure pivotal suppliers at the time of the annual peak load in the pivotal supplier indicative screen, which is the most likely point in time that a seller will be a pivotal supplier. For this reason, the Commission did not propose to expand the pivotal supplier analysis to other time periods.

Comments

46. Numerous commenters question whether the Commission should retain the current indicative screens in whole or in part. For example, Southern, Duke and EEI advocate abandoning the market share indicative screen altogether. They argue that the market share indicative screen is ''fatally flawed'' because it does not take into account wholesale demand in the relevant market[23] which makes it difficult for traditional utilities outside of RTOs/ISOs to pass.[24] E.ON. US. and PNM/Tucson separately argue that one must consider the level of demand that is seeking supply and, more particularly, what ability sellers have to exercise market power over those buyers.[25] In this regard, E.ON. US. and

[18] Sellers may deduct generation associated with their long-term firm requirements sales, unless the Commission disallows such deductions based on extraordinary circumstances.

[19] April 14 Order, 107 FERC ¶ 61,018 at P96.

[20] As noted below, the market share screen deducts generation capacity used for planned outages (that were done in accordance with good utility practice) in all four seasons in order to reflect the typical operation of generation units.

[21] The 20 percent threshold is consistent with § 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P13,103 (CCH 1988): ''The Department [of Justice] is likely to challenge any merger satisfying the other conditions in which the acquired firm has a market share of 20 percent or more.''

[22] *See April 14 Order, 107 FERC ¶ 61,018.*

[23] Southern at 11, Duke at 20, EEI at 6–7.

[24] Duke at 17, EEI at 8–9.

[25] E.ON. US. at 16–17 and PNM/Tucson at 5–6. According to E.ON. US. and PNM/Tucson, the past decade has seen strong development in the West of open access to transmission and the ownership of generating assets, solely or jointly, by formerly ''captive'' wholesale customers. As a result, any analysis that has as its foundation division of the market into suppliers and presumptively captive customers is at odds with present reality, in which wholesale customers have a host of suppliers seeking their business. E.ON. US. and PNM/Tucson state that an illustration of how open access in the West has enhanced the ability of load serving entities to secure competitive resources on an efficient scale across control areas is provided by a recent Southwest Public Power Resources Group

PNM/Tucson argue that to the extent the market share screen does not consider wholesale demand, it is not a useful indicator, and in fact is almost universally a false indicator of the ability of a seller to exercise market power over demand. Also, EEI argues that because of design flaws inherent in the market share screen as well as the negative impact that the use of this test has had since 2004 on the development of competitive wholesale markets (through the inappropriate exclusion of the majority of non-RTO utilities from participating in that market), the market share screen should be eliminated for all market power screening and analysis purposes.[26]

47. EEI contends that the Commission should use only the pivotal supplier screen for indicative screening purposes and the DPT pivotal supplier and market concentration analyses for the purposes of rebutting the presumption of generation market power that would result from the failure of the indicative pivotal supplier screen. EEI argues that if the Commission continues to use the market share screen as an initial screen, the Commission should not include a market share test as a component of any subsequent DPT analysis of market power.

48. E.ON U.S. and PNM/Tucson generally agree, stating that market share is an unreliable measure of market power in competitive energy markets and that the courts have long recognized that market share is not a reliable indicator of market power in regulated markets.[27] In particular, E.ON U.S. and PNM/Tucson argue that even a marginal failure of the market share screen results in a rebuttable presumption of market power that has tremendous consequences by forcing sellers to proceed to costly and time-consuming DPT analysis or agree to mitigation. As a result, the ''false positives'' arising from the market share screen dampen the vigor of competitive wholesale market participation by unnecessarily curtailing the market-based authority of entities that, in fact, lack market power (to the extent such entities choose not to pursue a costly and uncertain effort to rebut the presumption of market power created by the screen failure).[28]

49. Duke and Southern suggest that a wholesale contestable load analysis (also described as a ''competitive alternatives'' analysis)[29] should be added to the indicative screens, which would consider the amount of excess market supply available to serve the amount of wholesale demand seeking supply.[30] Generally, if available non-applicant supply is at least twice the contestable load, advocates of the contestable load analysis believe that is sufficient to make a finding that the market is competitive.[31] Other commenters agree that the market share indicative screen can diminish competition because sellers that are subjects of an FPA section 206 investigation tend to choose mitigation rather than challenge the presumption of market power.[32]

50. Duke argues that the Commission has yet to establish a need for using the market share indicative screen in addition to the pivotal supplier indicative screen in assessing the potential for the exercise of generation market power. In this regard, Duke argues that the Commission itself acknowledged in the April 14 Order (establishing the new indicative market power screens) that if a supplier passes the pivotal supplier indicative screen, it would not be able to exercise generation market power. Thus, Duke concludes that the use of any other indicative screens would appear to be redundant and an unwarranted burden on market-based rate sellers.[33] Further, Duke submits that neither of the rationales originally cited by the Commission in support of the market share screen—its ability to identify ''coordinating behavior,'' or its ability to detect the exercise of market power in off-peak periods—has been validated. In this regard, Duke submits that the potential for ''coordinating behavior'' should consider overall market concentration levels as measured by HHIs and in any event, such behavior is already subject to oversight and substantial penalties under the antitrust laws and the Commission's recently adopted rule prohibiting market manipulation. Further, Duke claims that the nearly universal failure rate of load-serving utilities under the market share indicative screen in their control areas underscores its limited value as an indicator of off-peak market power.[34]

51. Duke states that a review of filings by vertically integrated utilities that are not RTO participants shows that the vast majority have failed the market share screen in their control areas, and most have subsequently been forced to adopt some form of cost-based mitigation for wholesale sales in that market. Yet Duke is unaware of any credible evidence suggesting that any form of generation market power has been exercised by these utilities. Instead, Duke states that the Commission has revoked market-based rate authority and imposed mitigation on the basis of indicative screen results that suggest the potential for market power.[35] APPA/TAPS counter that the Commission should not limit its response to market power only to instances of its actual exercise; they note that the Commission considers whether a seller and its affiliates have market power or have mitigated it, not whether it has been exercised.[36]

52. Another commenter suggests substituting the HHI for the market share indicative screen or supplementing the indicative screens with the HHI, reasoning that the market must be evaluated, not just the individual market share.[37]

53. Southern states that the Commission should rely upon any indicative screens only in conjunction with an optional ''expedited track'' safe harbor review. Under Southern's proposal, the indicative screens would be voluntary and those submitting to and passing the screens would be permitted to retain or obtain market-based rate authority, subject to a proceeding under section 206 of the FPA, under which the party seeking to challenge the rate must submit substantial evidence justifying revocation. If a seller fails the screen(s), or if it elects to submit a DPT rather than voluntarily submit the indicative screens, then a robust market power assessment should be used to determine whether (or the extent to which) the

request for proposals for 255 MW in 2007, growing to 962 MW by 2014 in four control areas—Arizona Public Service, Salt River Project, Western Area Power Administration-Desert Southwest Region and Tucson Electric. (The Southwest Public Power Resources Group represents thirty-nine public power entities in Arizona, California, and Nevada.) See Southwestern Public Utilities Issue Long-Term RFP, ELECTRIC POWER DAILY, July 14, 2006, at 3.

[26] EEI at 10.

[27] *Citing Cost Mgmt. Servs., Inc.* v. *Wash. Natural Gas Co.,* 99 F.3d 937, 950–51 (9th Cir. 1996) *(Cost Management); Rebel Oil Co., Inc.* v. *Atl. Richfield Co.,* 51 F.3d 1421, 1439 (9th Cir. 1995) (Rebel); *S. Pac. Communications Co.* v. *AT&T Co.,* 740 F.2d 980, 1000 (D.C. Cir. 1984) *(Southern Pacific Communications); MCI Communications Corp.* v. *AT&T Co.,* 708 F.2d 1081, 1107 (7th Cir. 1983) *(MCI Communications); Mid-Tex. Communications Sys., Inc.* v. *AT&T Co.,* 615 F.2d 1372, 1386–89 (5th Cir. 1980) *(Mid-Tex Communications); Almeda Mall, Inc.* v. *Houston Lighting & Power Co.,* 615 F.2d 343, 354 (5th Cir. 1980) *(Almeda).*

[28] E.ON U.S. at 16; PNM/Tucson at 5–6.

[29] Dr. Pace at 12.

[30] Duke at 21, Southern at 16–17.

[31] Dr. Pace at 16.

[32] E.ON U.S. at 15–16; PNM/Tucson at 5–6, EEI at 10.

[33] Duke reply comments at 15 and n. 21.

[34] Duke reply comments at 15 and n. 22.

[35] Duke at 16.

[36] APPA/TAPS reply comments at 6–7, citing Duke at 16.

[37] Drs. Broehm & Fox-Penner at 2–4.

seller should be permitted to sell power at market-based rates.

54. In Southern's view, failure of the indicative screens should not give rise to a presumption of market power.[38] Southern argues that mere failure to pass a screen, without more robust market power assessments, is an insufficient basis upon which to base a presumption of market power. Southern argues this is because, in the case of the pivotal supplier screen, the Commission itself admits that it does not give a full picture and that the DPT provides better information. With regard to the market share screen, Southern argues that the market share screen has even more basic problems as an indicator of market power. Southern states that, because of the market share analysis' serious flaws, the great majority of integrated franchised public utilities inevitably will fail the market share screen. Thus, with respect to integrated franchised public utilities, the market share screen serves no real purpose other than to state the obvious: Integrated franchised public utilities build and maintain adequate resources to serve their native loads and inevitably will have market shares greater than 20 percent in their home control areas under the Commission's computational procedures. Southern states that, since the DPT reduces the level of false positives and is a more definitive means for determining the existence of market power, the Commission should use the DPT as the default test.[39] PPL agrees with Southern's proposal that the indicative screens be made voluntary.[40]

55. Southern states that if the market share screen is retained, it should be adjusted for forced outages because such capacity is not available. Southern also notes that forced outages are tracked and reported to the North American Electric Reliability Corporation (NERC), which presents generating unit availability statistics data for generator unit groups.[41]

56. NRECA disagrees with Southern's proposal, stating that forced outage deductions have little effect when applied to all sellers.[42] It also believes that sellers do not make forced outage deductions in long-term contracts; therefore, it is inappropriate to make the deduction for the market power tests.

57. While EPSA does not agree with some of the Commission's proposed changes to the horizontal analysis in the NOPR (*i.e.*, changes to the post-1996 exemption and the native load proxy), in general, EPSA supports the two indicative screens as a means for indicating that an entity might have market power.

58. EPSA notes that it is time to move beyond the battle over crafting the perfect screens, arguing: (1) It is likely no such perfect screens exist, as evidenced by the fact that stakeholders and the Commission have gone through several iterations to get to today's screens; and (2) in the end, the screens are only indicative measures. EPSA notes that failure of one or both of the screens does not brandish an entity with market power, but merely raises a flag that further analysis is necessary in order to assess an entity's ability to exercise market power. The current state of wholesale electricity markets, EPSA argues, requires indicative screens that are neither definitive nor an aperture letting everything pass, but rather a sieve that catches potential problems for further examination. EPSA agrees with retention of both of the current indicative screens and the ''next steps'' set forth for those entities that fail one or both of those screens.

59. Several other commenters also support retention of the indicative screens. Some of these commenters state that, because section 205 of the FPA requires rates to be just and reasonable, a market share indicative screen is appropriate to ensure that outcome. NRECA adds that ''[b]ecause of past or present State regulation, many traditional public utilities have acquired dominant market shares of generation capacity in their own control areas—sufficient to enable them to exercise market power absent regulation of their behavior. NRECA submits that regardless of the cause the incumbent public utilities will remain the dominant firms in their own control areas absent significant new market entry in the form of new generation construction in the control area by independent firms, or significant transmission construction to permit entry by generation outside the control area. Morgan Stanley also favors retaining the market share indicative screen, noting that failure of the market share indicative screen does not mean the process is unfair, and asserting that exclusive reliance on the pivotal supplier indicative screen may compromise market power detection.[43]

60. With regard to the suggestion that the Commission adopt a contestable load analysis, several commenters criticize the contestable load analysis, stating that it changes the focus of the market power analysis from the seller to the market. They counter that the contestable load analysis is unsound, with APPA/TAPS citing Federal Trade Commission (FTC) comments in this proceeding that such an analysis is flawed.[44] NRECA states that commenters have not provided sufficient justification for using a contestable load analysis.

61. With regard to Southern's suggestion that the indicative screens be made voluntary and function as a safe harbor, such that screen failure would simply mean that further review of the seller would be appropriate, but not merit a section 206 investigation, NRECA states that Southern's argument is contrary to law. NRECA argues that, as the proponent of a tariff allowing it to charge market-based rates, the public utility has the burden of proof to demonstrate that its wholesale rates will be disciplined by competition. NRECA submits that failing the indicative screens indicates that the seller has not yet provided '' 'empirical proof' '' that competition will drive down prices to just and reasonable levels as the FPA requires.[45]

Commission Determination

62. We adopt the proposal in the NOPR to retain both of the indicative screens. The intent of the indicative screens is to identify the sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. At the same time, sellers that do not pass the indicative screens are allowed to provide additional analysis

[38] Southern argues that, in the context of the indicative screens, the prejudice associated with integrated franchised public utility status is severe and instead of providing a fair or meaningful measure of market power, the market share screen operates to create *a priori* evidentiary presumption of guilt, the screen is improper, creates due process concerns, and should not be adopted for purposes of the final rule.

[39] Southern at 8, 11–13.

[40] PPL reply comments at 8.

[41] Southern at 14–15.

[42] NRECA reply comments at 18.

[43] Morgan Stanley reply comments at 10–11.

[44] APPA/TAPS reply comments at 11, NRECA reply comments at 13–14. The FTC filed comments in this proceeding in January 2006 on the contestable load test. FTC states that ''the historical contestable load proposal fails to include a number of potentially important considerations in its framework for assessing horizontal market power, and the elements that it does include are not considered in an economically sound manner. In sum, the proposal does not represent an analytical advance over existing techniques to evaluate horizontal market power, and it falls far short of the economically sound framework for market power analysis presented in the Merger Guidelines.'' The FTC defines the following specific problems with the contestable load analysis: the price is not considered in the assessment of available supply, contractual and legal restrictions on supply are ignored, and the contestable load analysis ignores transmission discrimination and transmission constraints, which delineate the market.

[45] NRECA reply comments at 20–21.

for Commission consideration. Because the indicative screens are intended to screen out only those sellers that raise no horizontal market power concerns, as opposed to other sellers that raise concerns but may not necessarily possess horizontal market power, we find it appropriate to use conservative criteria and to rely on more than one screen. A conservative approach at the indicative screen stage of the proceeding is warranted because, if a seller passes both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power.

63. The rebuttable presumption of horizontal market power that attaches to sellers failing one of the indicative screens is just that—a rebuttable presumption. It is not a definitive finding by the Commission; sellers are provided with several procedural options including the right to challenge the market power presumption by submitting a DPT analysis, or, alternatively, sellers can accept the presumption of market power and adopt some form of cost-based mitigation.[46] Accordingly, we will adopt the proposal to continue to use the two indicative screens and find that failure of either indicative screen creates a rebuttable presumption of market power. We reiterate our finding that ''[f]ailure to pass either of the indicative screens * * * will constitute a prima facie showing that the rates charged by the seller pursuant to its market-based rate authority may have become unjust and unreasonable and that continuation of the seller's market-based rate authority may no longer be just and reasonable.'' [47]

64. This approach, contrary to the claims of several commenters, will help to further competitive markets by allowing sellers without market power to sell power at market-based rates, and it will similarly give customers security that sellers that fail the screens are required to submit to further scrutiny and/or mitigation.

65. The pivotal supplier and market share indicative screens measure different aspects of market power. As the Commission stated in the April 14 Order, the uncommitted pivotal supplier indicative screen measures the ability of a firm to dominate the market at peak periods. The uncommitted market share analysis provides a measure as to whether a supplier may have a dominant position in the market, which is another indicator of potential unilateral market power and the ability of a seller to effect coordinated interaction with other sellers. The market share screen is also useful in measuring market power because it measures a seller's size relative to others in the market, in particular, the seller's share of generating capacity uncommitted after accounting for its obligations to serve native load. The market share screen provides a snapshot of these market shares in each season of the year. Taken together, the indicative screens can measure a seller's market power at both peak and off-peak times.[48] Both market share and pivotal supplier indicative screens are appropriate first steps for the Commission to use in determining if it needs a more robust analysis to determine whether the seller has market power. We conclude that having two screens as backstops to one another will better assist us in determining the existence of potential market power. Accordingly, we reject the suggestion of several commenters to abandon the market share indicative screen. We will retain both the pivotal supplier and market share indicative screens as described in the NOPR, as well as apply the rebuttable presumption of market power for those sellers that fail either indicative screen.[49]

66. In addition, the Commission will not adopt suggestions to alter the indicative screens in order to incorporate a contestable load analysis, as proposed by EEI and others. As noted by the FTC, APPA/TAPS, and NRECA, the contestable load analysis is flawed because, among other things, it does not consider control of generation through contracts. The Commission explained in the April 14 Order that the roles of the indicative screens are meant to be complementary. The pivotal supplier indicative screen indicates whether demand can be met without some contribution of supply by the seller at peak times, while the market share indicative screen indicates whether the seller has a dominant position in the market and may therefore have the ability to exercise horizontal market power, both unilaterally and in coordination with other sellers.[50] The contestable load analysis is essentially a variant on the pivotal supplier screen with differences in the calculation of wholesale load and the test thresholds, because, like the pivotal supplier screen, it addresses whether suppliers other than the seller can meet the demand in the relevant market. Therefore incorporating such an analysis would not improve our ability to establish a presumption of whether a seller has market power. The contestable load analysis therefore would add little useful information, and without the market share indicative screen, the Commission would have insufficient information because there would be no analysis of a seller's size relative to the other sellers in the market, and no information on the seller's market power during off-peak periods.

67. In addition, the contestable load analysis fails to consider the relative price of the competing supplies. Commenters have argued that if available non-applicant supply is at least twice the contestable load, the market is competitive. However, this analysis fails to consider whether the available non-applicant supply is competitively priced and, thus, in the market. This weakness in the contestable load analysis is addressed in the DPT analysis which considers only supply that is competitively priced.

68. We also reject arguments by E.ON U.S. and PNM/Tucson that the wholesale market share screen should be replaced because, they argue, it does not consider the size of the wholesale supply in the relevant market relative to the wholesale demand in that market. E.ON. U.S. and PNM/Tucson are requesting an analysis very similar to the contestable load analysis, whose defining characteristic is measuring the wholesale supply market relative to wholesale demand, which, as stated above, is essentially the same as the pivotal supplier screen, and would therefore add little useful information to the screening process.

69. We reject Duke's claim that because neither of the rationales originally cited by the Commission in support of the market share indicative screen—its ability to identify ''coordinating behavior,'' or its ability to detect the exercise of market power in off-peak periods—has been validated, the wholesale market share indicative screen is unnecessary. Specifically, the Commission believes that the ability of market participants to exercise market power through ''coordinating behavior'' is a legitimate concern under the FPA, in addition to the fact that it has long been recognized by the antitrust

[46] In the April 14 Order, the Commission stated that proposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate. For example, a seller could propose to transfer operational control of enough generation to a third party such that the applicant would satisfy our generation market power concerns. April 14 Order, 107 FERC ¶ 61,018 at n. 142.

[47] April 14 Order, 107 FERC ¶ 61,018 at P 209.

[48] April 14 Order, 107 FERC ¶ 61,018 at P 72.

[49] As we noted in the July 8 Order, a number of those commenters that proposed eliminating the market share screen had supported it as a viable alternative in the past. July 8 Order, 108 FERC ¶ 61,026 at P 87.

[50] April 14 Order, 107 FERC ¶ 61,018 at P 72.

authorities.[51] The Commission also believes it is possible to exercise market power in off-peak periods because during such times the amount of supply in the market may be greatly reduced (*e.g.*, because of planned outages for plant maintenance), meaning that a seller that is not dominant at peak times might be at off-peak.

70. Moreover, we agree with APPA/TAPS that market-based rate assessments are used to determine the ability to exercise, not the exercise of, market power. The Commission need not wait passively until market power is exercised. Rather, it is incumbent on the Commission to set policies that will ensure that rates remain just and reasonable under section 205 of the FPA. Requiring sellers to submit screens that analyze the sellers' potential to exercise market power is consistent with such a policy.

71. We are unpersuaded by E.ON U.S.'s and PNM/Tucson's argument that ''false positives'' arising from the market share screen dampen the vigor of competitive wholesale market participation by unnecessarily curtailing the market-based rate authority of entities that, according to E. ON. U.S. and PNM/Tucson, lack market power. We recognize that a conservative screen may result in some false positives, but must weigh that against the cost of the false negatives that would occur if we adopted a less conservative screen or eliminated the market share indicative screen.

72. E.ON U.S. and PNM/Tucson, to support their point, cite several court cases in which market shares were alleged not to be reliable indicators of market power in regulated markets. However, the cases cited are not relevant to the issue of whether the Commission should retain the wholesale market share screen. The purpose of our indicative screens is to distinguish sellers that may raise horizontal market power concerns and those that do not; the market share screen is not the end of our horizontal market power analysis. In contrast, the cases cited by E.ON U.S. and PNM/Tucson[52] involve allegations of unlawful restraint of trade in violation of the Sherman Act,[53] a Federal antitrust statute prohibiting trade monopolies. The focus in such cases (whether a company has violated the Sherman Act) and the standard for making such a determination is different than the focus of the Commission at the indicative screen stage of the horizontal market power analysis (identifying sellers that require further horizontal market analysis without making a definitive finding regarding market power).

73. On both theoretical and practical grounds, we reject the argument by EEI and others that the market share indicative screen can diminish competition because some sellers that are the subject of a section 206 investigation choose mitigation rather than challenge the presumption of market power. First, mitigating a seller with market power ensures that the other sellers in the market cannot benefit from an artificially high market price due to the seller with market power exercising market power. Second, in our experience, sellers that choose mitigation rather than challenge the presumption of market power have market shares that are likely to indicate a dominant position in a geographic market.[54] In addition, many sellers have successfully rebutted the presumption of market power after failing one of the indicative screens.[55]

74. Further, we will not adopt the suggestion to substitute the HHI for the market share indicative screen or to supplement the indicative screens with the HHI. The indicative screens are used to separate sellers who are presumed to have market power from those that, absent extraordinary and transitory circumstances, clearly do not. We will not substitute the market share screen with an HHI screen because, as we have stated above, the seller's market share conveys useful information about its ability to exercise market power, so eliminating the market share screen in favor of the HHI could increase the risk of false negatives.[56] In addition, a high HHI can be the result of high market shares of sellers in the market other than the seller, and the focus of our analysis is on the seller's ability to exercise market power, so the HHI would provide little additional information to allow us to identify those sellers who clearly do not have market power. Finally, the HHI primarily provides information on the ability of sellers to exercise market power through coordinated behavior, while the market share screen primarily provides information on a particular seller's ability unilaterally to exercise market power. We will not supplement the indicative screens with the HHI screen because the indicative screens are sufficiently conservative to identify those sellers that have a rebuttable presumption of market power, without having to add an additional layer of review at the initial stage.

75. We clarify that sellers and intervenors may present alternative evidence such as a DPT study or historical sales and transmission data to support or rebut the results of the indicative screens. For example, intervenors could present evidence based on historical wholesale sales data or challenge the assumption that competing suppliers inside a balancing authority area have access to the market (such a challenge could take into account both the actual historical transmission usage at the time of the study as well as the amount of available transmission capacity at that time).[57] A seller may present evidence in support of a contention that, notwithstanding the results of the indicative screens, it does not possess market power.[58] However, sellers should not expect that the Commission will postpone initiating a section 206 investigation to protect customers while it examines this supplemental information if screen failures are indicated.[59] Nevertheless, the Commission may factor in this alternative evidence before deciding whether to initiate a section 206 investigation if the alternative evidence is appropriately supported, comprehensive and unambiguous, and

[51] *See* 1992 FTC/DOJ 1992 Horizontal Merger Guidelines sec. 2.1.

[52] *Cost Management*, 99 F.3d 937; *Rebel Oil*, 51 F.3d 1421; *S. Pac. Communications*, 740 F.2d 780; *MCI Communications*, 708 F.2d 1081; *Mid-Tex Communications*, 615 F.2d 1372; and *Almeda*, 615 F.2d 343.

[53] 15 U.S.C. 2, which states: ''Every person who shall monopolize, or attempt to monopolize, or combine or conspire with any other person or persons, to monopolize any part of the trade or commerce among the several States, or with foreign nations, shall be deemed guilty of a felony, and, on conviction thereof, shall be punished by fine not exceeding $100,000,000 if a corporation, or, if any other person, $1,000,000, or by imprisonment not exceeding 10 years, or by both said punishments, in the discretion of the court.''

[54] *See, e.g., Aquila, Inc.*, 112 FERC ¶ 61,307 (2005); *Carolina Power & Light Co.,* 113 FERC ¶ 61,130 (2005); *The Empire District Electric Co.,* 116 FERC ¶ 61,150 (2006); *MidAmerican Energy Co.*, 117 FERC ¶ 61,178 (2006); *Xcel Energy Services Inc.*, 117 FERC ¶ 61,180 (2006).

[55] *See, e.g., Kansas City Power and Light Co.*, 113 FERC ¶ 61,074 (2005); *PPL Montana, LLC*, 115 FERC ¶ 61,204 (2006); *PacifiCorp*, 115 FERC ¶ 61,349 (2006); *Tucson Electric Power Co.*, 116 FERC ¶ 61,051 (2006); *Acadia Power Partners, LLC*, 113 FERC ¶ 61,073 (2005).

[56] For example, in a market with one seller with a 35 percent market share and 13 sellers each with 5 percent market shares, the HHI would be 1,550 (1,225 + 13(25)), which would not fail the 2,500 HHI threshold or even the proposed lower 1,800 HHI threshold. In such a market, a firm with a 35 percent market share could have the ability to exercise market power, which would not be picked up by an HHI screen.

[57] *Id.* at P 37.

[58] *Id.* at n. 11.

[59] *See, e.g., LG&E Energy Mtkg. Inc.*, 111 FERC ¶ 61,153 at P 21, 22 (2005); *Tampa Electric Co.*, 110 FERC ¶ 61,206 at P 24, 25 (2005); *Entergy Services, Inc.*, 109 FERC ¶ 61,282 at P 36 (2004).

conducive to prompt review by the Commission.

76. We will not adopt Southern's suggestion that the indicative screens be made voluntary. We will continue to require that sellers submit the indicative screens or concede the presumption of market power before they file a DPT. However, as discussed above, a seller may submit with its indicative screens a DPT as alternative evidence. As stated above, submission of a DPT analysis as alternative evidence at the same time a seller submits the indicative screens may result in the Commission instituting a section 206 proceeding to protect customers, based on failure of an indicative screen, while the Commission considers the merits of the DPT analysis.

77. We do not agree with Southern's view that failure of the indicative screen(s) does not provide a sufficient basis to establish a rebuttable presumption of market power. The indicative screens are intended to identify the sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. Sellers failing one or both of the indicative screens, on the other hand, are identified as sellers that potentially possess horizontal market power and for which a more robust analysis is required. The uncommitted pivotal supplier screen focuses on the ability to exercise market power unilaterally. Failure of this screen indicates that some or all of the seller's generation must run to meet peak load. The uncommitted market share analysis indicates whether a supplier has a dominant position in the market. Failure of the uncommitted market share screen may indicate the seller has unilateral market power and may also indicate the presence of the ability to facilitate coordinated interaction with other sellers. It is on this basis that we find that a rebuttable presumption of market power is warranted when a seller fails one or both of the indicative screens. However, we agree with Southern that the DPT is a more definitive means for determining the existence of market power. As a result, we allow sellers that have failed one or both of the indicative screens to rebut the presumption of market power by performing the DPT. Further, because failure of one or both of the indicative screens only creates a rebuttable presumption of market power and sellers have a Commission-endorsed analysis that they can use to rebut that presumption (the DPT), we find without merit Southern's view that the indicative screens create *a priori* evidentiary presumption of guilt, are improper, and create due process concerns.

78. With regard to Southern's suggestion that we use the DPT as the default test, we find that if we were to do so our ability to protect customers while the analysis is evaluated could be compromised. The DPT is a more involved and complex analysis. The Commission has also at times set a DPT analysis for evidentiary hearing which greatly extends the time between when the DPT is submitted to the Commission and when a final decision is rendered. The rates customers are subject to during the time period before the issuance of a Commission order addressing a seller's DPT would not be subject to refund and, accordingly, the customers would be unprotected if the seller ultimately is found to have market power. However, under our current policy, and as adopted herein, if a seller wishes to file a DPT rather than the indicative screens it may do so. In doing so, the seller concedes that it fails the indicative screens, which concession establishes a rebuttable presumption of market power, and the Commission will issue an order initiating a section 206 proceeding to investigate whether the seller has market power and establishing a refund effective date for the protection of customers while the Commission evaluates the filed DPT. In the case of a seller that concedes the failure of one or both of the screens and submits the DPT in the same filing, the Commission is able to establish a refund effective date at an earlier time than if the seller were able to skip the screen stage entirely and file a DPT without conceding a screen failure.

79. We will reject Southern's request that forced outages be deducted from capacity. As we stated in the July 8 Order, ''forced outages are non-recurring events that do not reflect normal operating conditions.'' [60] Allowing deduction of forced outages will generally not change indicative screen results, because all sellers will be able to deduct forced outages, offsetting each other. In the unlikely event that forced outage numbers were not completely offsetting, allowing forced outages in the indicative screens would benefit owners of relatively unreliable fleets at the expense of owners of relatively reliable fleets.

[60] July 8 Order, 108 FERC ¶ 61,026 at P 68.

2. Indicative Market Share Screen Threshold Levels and Pivotal Supplier Application Period

Commission Proposal

80. In the NOPR, the Commission proposed to retain the 20 percent threshold for the wholesale market share screen (*i.e.*, with a market share of less than 20 percent, the seller would pass the screen). The Commission stated that since the screens are indicative, not definitive, a relatively conservative threshold for passing them was appropriate. Indeed, pursuant to the horizontal market power analysis, the Commission will not make a definitive finding that a seller has market power unless and until the more robust analysis, the DPT, is considered.

81. The Commission proposed to continue the use of annual peak load in the pivotal supplier analysis and not to expand the pivotal supplier analysis to include monthly assessments. It stated that the pivotal supplier analysis examines the seller's market power during the annual peak, and that the hours near that point in time are the most likely times that a seller will be a pivotal supplier.

a. Market Share Threshold

Comments

82. A number of commenters argue that 20 percent is too low a threshold for the market share indicative screen. Some point out that, given native load requirements, it is very difficult for investor-owned utilities outside of RTOs/ISOs to fall below the 20 percent threshold for the market share indicative screen.[61] Duke also notes that the 20 percent criterion is incompatible with regional planning requirements because, according to Duke, the amount of capacity needed to satisfy regional planning reserve margins ''would place the utility at substantial risk of exceeding the 20 percent threshold.'' [62]

83. E.ON U.S. argues that, because the courts have not considered a 20 percent market share to indicate a market power concern, associating a market share indicative screen failure with a presumption of market power is inappropriate.[63] Additionally, Progress

[61] *See, e.g.*, Southern at 8–9, Duke at 15–16, EEI at 8–9.

[62] Duke at 17.

[63] *See* E.ON U.S. at 14–15, n.18, *citing PepsiCo, Inc.* v. *Coca-Cola Co.*, 315 F.3d 101, 109 (2d Cir. 2003) (''Absent additional evidence, such as an ability to control prices or exclude competition, a 64 percent market share is insufficient to infer monopoly power.''); *AD/SAT* v. *Associated Press*, 181 F.3d 216, 229 (2d Cir. 1999) (concluding that 33 percent market share is insufficient to show a dangerous probability of monopoly power); *United*

Continued

Energy argues that it is inappropriate to associate failure of the market share screen with a presumption of market power when U.S. Department of Justice (DOJ) merger guidelines state that only firms with 35 percent or more market share have market power.[64]

84. PPL states that it agrees that the 20 percent threshold should be replaced by a 35 percent threshold in the market share screen and argues that such an increase will avoid the false-positive failure rate of the indicative screens, and the cost, time and repercussions in the financial markets of the extended pendency of a market-based rate renewal proceeding while a DPT is conducted and considered.[65]

85. In reply, APPA/TAPS state that there is no reason to raise the market share indicative screen threshold above 20 percent simply because investor-owned utilities have trouble passing the market share indicative screen.[66] NRECA and TDU Systems note that the factors that EEI believes make it difficult to pass the indicative screens—a large amount of reserves and little available transfer capability—are precisely the factors to consider when evaluating whether a market is competitive.[67]

86. Rather than raising the threshold level, TDU Systems propose to lower the threshold to 15 percent for the market share indicative screen, claiming that 20 percent was never justified by the Commission or shown to be the right balance.[68] Citing Commission and judicial precedent, TDU Systems also note that the grant of market-based rate authority cannot be made without the discipline of market forces.[69]

87. These commenters cite a recent decision of the U.S. Court of Appeals for the Ninth Circuit [70] to buttress their positions, arguing that even market shares lower than 20 percent can lead to market manipulation.

88. In reply to these arguments, Duke states that certain commenters' reliance on this is mistaken because that decision addressed market manipulation, not market power.[71] Duke asserts that virtually any supplier, regardless of its market share, has some ability to manipulate market outcomes by engaging in anomalous bidding practices.

Commission Determination

89. The Commission will retain the 20 percent market share threshold for the indicative market share screen. EEI and others argue that the Commission should use a 35 percent threshold as a presumption of market power because the DOJ merger guidelines state that only firms with 35 percent or more market share have market power. As the Commission stated in the July 8 Order, however, in a market comprised of five equal-sized firms with 20 percent market shares, the HHI is 2,000, which is above the DOJ/FTC HHI threshold of 1,800 for a highly concentrated market, and in markets for commodities with low demand price-responsiveness like electricity, market power is more likely to be present at lower market shares than in markets with high demand elasticity.[72] Therefore, we will retain a conservative 20 percent threshold for this indicative screen.

90. When arguing that a 20 percent threshold for the market share screen is too low, E.ON. U.S. and PNM/Tucson ignore that the indicative screens are based on uncommitted capacity, not total capacity. When calculating uncommitted capacity for the market share screen, a seller deducts from its total capacity the capacity dedicated to long-term sales contracts, operating reserves,[73] planned outages, and native load [74] as measured by the appropriate native load proxy. As a result, a substantial amount of seller capacity may not be counted in measures of market share. Therefore, it is inappropriate to compare market shares based on uncommitted capacity to the market shares in the cases that E.ON. U.S. and PNM/Tucson cite.

91. We further note that other commenters have argued that the 20 percent threshold is too high. We disagree. The 20 percent threshold is meant to strike a balance between having a conservative but realistic screen and imposing undue regulatory burdens. The Commission's experience in the context of market-based rate proceedings demonstrates this point. In the three years since the April 14 Order, the Commission has revoked the market-based rate authority of two sellers, thirteen sellers relinquished their market-based rate authority, and six companies satisfied the Commission's concerns for the grant of market-based rate authority at the DPT phase. In addition, intervenors have the opportunity to present other evidence such as historical data in order to rebut the presumption that sellers lack market power.[75] Moreover, no commenter advocating a 15 percent threshold for the market share has shown why it is superior to the current 20 percent threshold. Therefore, we find that the 20 percent market share threshold strikes the right balance in seeking to avoid both ''false negatives'' and ''false positives'' and we will not reduce the wholesale market share screen to 15 percent, as suggested by TDU Systems.

92. The Commission does not accept Duke's assertion that the market share indicative screen is incompatible with regional planning requirements. The April 14 Order allows operating reserves necessary for reliability, as determined by State or regional reliability councils,[76] to be deducted from total capacity attributed to the seller.

93. We also reject the argument that the 20 percent threshold is too low because of native load obligations of investor-owned utilities outside of RTOs. First, the calculation of 20 percent is the same regardless of whether a seller is located in an RTO or not. Second, as discussed herein, we allow for a native load deduction in the wholesale market share screen and are increasing the deduction to address concerns raised by investor-owned utilities and others. Given the increased native load deduction, our market share screen adequately incorporates investor-owned utilities' native load obligations while necessarily maintaining the conservative nature of the screens.

b. Pivotal Supplier Application Period

Comments

94. Some commenters recommend that the pivotal supplier indicative screen should be applied monthly, rather than just in a seller's peak month. They reason that sellers, though not pivotal in the highest demand period, might be pivotal at different times of the year or in off-peak periods, such as in the spring or fall when power plants are on planned outages.[77]

Commission Determination

95. The Commission will not require the pivotal supplier indicative screen to be applied monthly, as some commenters suggest, because we believe

Air Lines, Inc. v. *Austin Travel Corp.*, 867 F.2d 737, 742 (2d Cir. 1989) (finding that 31 percent market share does not constitute a national monopoly).

[64] Progress Energy at 7, citing EEI at 6–10.

[65] PPL reply comments at 7.

[66] APPA/TAPS reply comments at 12.

[67] NRECA reply comments at 16, TDU Systems reply comments at 10, citing EEI at 8.

[68] TDU Systems at 7.

[69] TDU Systems at 5.

[70] *Pub. Utils. Comm'n of Calif.* v. *FERC*, 462 F.3d 1027, at 1039 (9th Cir. 2006) (*CPUC*) (''As became clear in hindsight, even those who controlled a relatively small percentage of the market [in the California market during 2000 and 2001] had sufficient market power to skew markets artificially.'').

[71] Duke reply comments at 18, citing *CPUC*.

[72] July 8 Order, 108 FERC ¶ 61,026 at P 96.

[73] April 14 Order 107 FERC ¶ 61,018 at P 94.

[74] *Id.* at P 100.

[75] *Id.* at P 97.

[76] April 14 Order, 107 FERC ¶ 61,018 at P 96.

[77] See, *e.g.* APPA/TAPS at 66–67, NRECA at 19–20.

it is unnecessary and overly burdensome to do so. Even though conditions of tight supply may occur at other times of the year or in abnormal operating conditions, the combination of the pivotal supplier analysis and the wholesale market share screen is sufficient, because suppliers with market power at such times are also likely to fail at least one of these screens. Moreover, if intervenors believe that a seller is pivotal during non-peak periods, they are permitted to file evidence to that effect. Accordingly, using only the peak month in the pivotal supplier indicative screen is appropriate. We note that if a seller fails the indicative screens and submits a DPT, it is required to provide a pivotal supplier analysis for each season and for both peak and non-peak hours.

3. DPT Criteria

Commission Proposal

96. With regard to the DPT analysis, the Commission proposed to retain the current thresholds (20 percent for the market share analysis and 2,500 for the HHI analysis), as well as the current practice of weighing all the relevant factors presented in determining whether a seller does or does not have horizontal market power. The Commission proposed to continue to do so on a case-by-case basis, weighing such factors as available economic capacity, economic capacity, market share, HHIs, and historical sales and transmission data.[78]

Comments

97. Several commenters suggest changes to the DPT criteria. One suggested change is to emphasize[79] or rely exclusively[80] on the available economic capacity measure, in order to properly account for native load. For example, one commenter argues that the economic capacity prong of the DPT analysis is not a useful indicator of the presence or absence of market power when applied to vertically integrated utilities in their home control areas because that analysis completely disregards native load obligations, making this prong virtually unpassable by such utilities. This commenter also notes that even using the available economic capacity measure, a seller with a market share above 35 percent would fail the DPT ''even though there is no real market power problem because the in-area wholesale customers have access to ample supplies of competitively priced power.''[81] In this regard, he argues that the DPT should be changed to take into account ''competitive alternatives available for wholesale customers.''[82]

98. Several other commenters disagree with the 2,500 HHI threshold for the DPT. Some reason that a 2,500 HHI threshold is not well justified and that an 1,800 HHI threshold is more appropriate because this is the criterion used in a highly concentrated market. They argue that if a 2,500 HHI threshold is used, it should be used with a 15 percent market share because these are the criteria of the oil-pipeline test from which the HHI 2,500 criterion is obtained.[83] State AGs and Advocates note that the Commission has never systematically attempted to correlate the results of the pivotal supplier indicative screen, the market share indicative screen, or the DPT (including HHI results) proposed in the NOPR with actual independently derived data and measures as to the existence of market power in any wholesale electricity market in the U.S.[84] Without having done this type of systematic and quantitative evaluation of the proposed market power tests based on some type of independent verification, State AGs and Advocates contend that the Commission cannot be confident that the three proposed tests are reasonably accurate and, therefore, useful tests to determine the existence of market power in any electricity market. For example, State AGs and Advocates ask how the Commission knows if an HHI corresponds to the point at which market power begins, and whether it varies by factors such as input price, generation mix and different market structures through the country.[85]

99. Furthermore, State AGs and Advocates claim that the DPT is not an adequate tool for assessing market power ''in any context.'' First, they state that the DPT will not discern bidding strategies of different suppliers. In addition, they assert that a DPT does not consider the differences between fundamentally different types of market structures: short-term energy only markets, short-term capacity markets, ancillary service markets, and long-term contract markets for energy and capacity.[86]

100. A number of commenters believe that the HHI threshold sufficient for passage of the DPT should remain at 2,500.[87] PPL states that lowering the HHI threshold to 1,800 will cause more false positives and direct capital away from the generation sector.

101. EEI and Progress Energy recommend that only the pivotal supplier and HHI analyses of the DPT should be retained, particularly if the market share analysis under the indicative screens is retained. They argue that the pivotal supplier and HHI analyses are more than sufficient to determine whether the potential for market power exists.[88]

102. A few commenters are skeptical about the need for a DPT. Southern states that ''granting market-based rates should not require the same analysis as for a merger,'' and that the Commission should reconsider using the DPT.[89] In this regard, Southern argues that unlike mergers, which are difficult and costly to undo, the Commission has the ability to continuously police the exercise of market power. Further, Southern states that the Energy Policy Act of 2005 provides for stiff civil and criminal penalties. Southern adds that the Commission recently issued new rules against market manipulation to thwart exercises of market power.

103. AARP expresses concern about the lack of competition in wholesale electric markets. It argues that market-based rate reviews are intended to determine whether the seller's market-based rates will be just and reasonable, not whether a seller passes the various tests. AARP argues that real-world evidence that may not fit neatly within the specified market-based rate criteria must be considered before the Commission can conclude that a seller lacks market power. AARP states that, as the NOPR recognizes (PP 63–64), both historical and forward-looking evidence should be considered.

Commission Determination

104. The Commission will continue to use the DPT for companies that fail the

[78] *Economic capacity* means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. *Available economic* capacity means the amount of generating capacity meeting the definition of economic capacity less the amount of generating capacity needed to serve the potential supplier's native load commitments. *See generally* April 14 Order, 107 FERC ¶ 61,018 at Appendix F.

[79] Dr. Pace at 9.

[80] Southern at 20–21, EEI at 15.

[81] Dr. Pace at 11–12.

[82] Dr. Pace at 12–13.

[83] APPA/TAPS at 78–79, TDU Systems at 18, Montana Counsel at 15 (referring to APPA/TAPS comments).

[84] State AGs and Advocates state that by ''independently'' derived measures of market power they mean measures derived using different methodologies (and more accurate methodologies) than the Commission proposed in the NOPR.

[85] States AGs and Advocates at 36–37.

[86] State AGs and Advocates reply comments at 6–7.

[87] MidAmerican reply comments at 2, citing EEI comments; PPL reply comments at 8; EEI reply comments at 23.

[88] EEI at 10–12, Progress at 8.

[89] Southern at 19–20.

market power indicative screens. The DPT is a well-established test that has been used routinely by the Commission to analyze market power in the merger context. The fact that it is used in section 203 cases does not demonstrate that it is inappropriate for market-based rate cases. Rather, it provides a well-established tool for assessing market power that is known and widely used in the electric industry. Moreover, in both contexts, the DPT allows for the calculation of market shares and market concentration values under a wide range of season and load conditions.

105. Sellers failing one or more of the initial screens will have a rebuttable presumption of market power. If such a seller chooses not to proceed directly to mitigation, it must present a more thorough analysis using the DPT. The DPT is also used to analyze the effect on competition for transfers of jurisdictional facilities in section 203 proceedings,[90] using the framework described in Appendix A of the Merger Policy Statement and revised in Order No. 642.[91]

106. The DPT defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.[92] The results of the DPT can be used for pivotal supplier, market share and market concentration analyses.

107. Using the economic capacity for each supplier, sellers should provide pivotal supplier, market share and market concentration analyses. Examining these three factors with the more robust output from the DPT will allow sellers to present a more complete view of the competitive conditions and their positions in the relevant markets.

108. Under the DPT, to determine whether a seller is a pivotal supplier in each of the season/load conditions, sellers should compare the load in the destination market to the amount of competing supply (the sum of the economic capacities of the competing suppliers). The seller will be considered pivotal if the sum of the competing suppliers' economic capacity is less than the load level (plus a reserve requirement that is no higher than State and Regional Reliability Council operating requirements for reliability) for the relevant period. The analysis should also be performed using available economic capacity to account for sellers' and competing suppliers' native load commitments. In that case, native load in the relevant market would be subtracted from the load in each season/load period. The native load subtracted should be the average of the native load daily peaks for each season/load condition.

109. Each supplier's market share is calculated based on economic capacity. The market shares for each season/load condition reflect the costs of the sellers' and competing suppliers' generation, thus giving a more complete picture of the sellers' ability to exercise market power in a given market. For example, in off-peak periods, the competitive price may be very low because the demand can be met using low-cost capacity. In that case, a high-cost peaking plant that would not be a viable competitor in the market would not be considered in the market share calculations, because it would not be counted as economic capacity in the DPT. Sellers must also present an analysis using available economic capacity and explain which measure more accurately captures conditions in the relevant market.

110. Under the DPT, sellers must also calculate the market concentration using the HHI based on market shares.[93] HHIs have been used in the context of assessing the impact of a merger or acquisition on competition. However, as noted by the U.S. Department of Justice in the context of designing an analysis for granting market-based pricing for oil pipelines, concentration measures can also be informative in assessing whether a supplier has market power in the relevant market. ''The Department and the Commission staff have previously advocated an HHI threshold of 2,500, and it would be reasonable for the Commission to consider concentration in the relevant market below this level as sufficient to create a rebuttable presumption that a pipeline does not possess market power.'' [94]

111. A showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors. Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interaction among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that that it would be unlikely to possess market power in an unconcentrated market (HHI less than 1,000). As with our initial screens, sellers and intervenors may present evidence such as historical wholesale sales. Those data could be used to calculate market shares and market concentration and could be used to refute or support the results of the DPT. The Commission encourages the most complete analysis of competitive conditions in the market as the data allow.

112. We will continue to weigh both available economic capacity and economic capacity when analyzing market shares and HHIs. Based on our substantial experience in applying the DPT over the past decade, we have found that both analyses are useful indicators of suppliers' potential to exercise market power, and we are unwilling to rely solely on one measure or the other.[95] For example, in markets where utilities retain significant native load obligations, an analysis of available economic capacity may more accurately assess an individual seller's competitiveness, as well as the overall competitiveness of a market, because available economic capacity recognizes the native load obligations of the sellers. On the other hand, in markets where the

[90] 16 U.S.C. 824b (2000).

[91] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 FR 68,595 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,044 (1996), *reconsideration denied*, Order No. 592–A, 62 FR 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement); *see also* Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 FR 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 (2000), *order on reh'g*, Order No. 642–A, 66 FR 16,121 (2001), 94 FERC ¶ 61,289 (2001).

[92] Super-peak, peak, and off-peak, for Winter, Shoulder and Summer periods and an additional highest super-peak for the Summer.

[93] The HHI is the sum of the squared market shares. For example, in a market with five equal size firms, each would have a 20 percent market share. For that market, HHI = $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2 = 400 + 400 + 400 + 400 + 400 = 2{,}000$.

[94] *See* Comments of the United States Department of Justice in response to Notice of Inquiry Regarding Market-Based Ratemaking for Oil Pipelines, Docket No. RM94–1–000 (January 18, 1994).

[95] *See, e.g., Tampa Electric Company,* 117 FERC ¶ 61,311 (2006); *PacifiCorp,* 115 FERC ¶ 61,349 (2005); *Tucson Electric Power Company,* 116 FERC ¶ 61,051(2006); *Duke Power, a Division of Duke Energy Corporation,* 111 FERC ¶ 61,506 (2005); and *Kansas City Power and Light Company,* 113 FERC ¶ 61,074 (2005).

sellers have been predominantly relieved of their native load obligations, an analysis of economic capacity may more accurately reflect market conditions and a seller's relative size in the market.

113. Likewise, we find the HHI market concentration measure to be useful in assessing the market power of individual sellers, and it complements the market share and pivotal supplier measures in the DPT stage of the analysis. Furthermore, no commenter has presented a compelling argument for why the Commission should lower or raise the HHI threshold in the DPT. Accordingly, we will retain 2,500 as the appropriate threshold for passing this part of the DPT for the reasons we stated in the April 14 Order.[96] We will not adopt the suggestion to lower the market share threshold to 15 percent from 20 percent, for the reasons set forth above, in the NOPR and July 8 Order.[97] Commenters have presented no compelling reason to do so, and in our experience since the April 14 Order, we have not seen cases where the HHI was over 2,500 and the seller's market share was between 15 and 20 percent, which would be the type of situation about which APPA/TAPS and others are concerned. Accordingly, such a reform would not likely result in additional findings of market power.

114. State AGs and Advocates claim that the DPT is not an adequate tool for assessing market power because it will not discern bidding strategies of different suppliers. However, State AGs and Advocates miss the point of the analysis: by determining whether a seller has capacity that can compete in the market under various season and load conditions, the DPT provides an accurate picture of market conditions. Examining market conditions allows the Commission to determine whether a seller has market power. The DPT does this by examining short-term energy markets and, in particular, sellers' available generation capacity. In addition, absent entry barriers, and a specific finding of market power, the Commission has said that long-term markets are competitive. With regard to ancillary services, as discussed herein, the Commission requires market power analyses for those services to support a request for market-based rate authority. Assessing competing suppliers' bidding strategies, ex ante, would not illuminate the state of the market and the ability of sellers to alter prices within it.

115. We also reject Southern's argument that the DPT analysis is unnecessary because of the Commission's enhanced civil penalty authority and continuing policing of sellers with market-based rate authorization. While those are critical components of our program to ensure just and reasonable market-based rates, they are not a substitute for an analysis of the potential market power of sellers seeking market-based rate authority. In addition, Southern's argument that rules against market manipulation will thwart all exercises of market power is speculative.

116. We will not change the DPT to take into account competitive alternatives available for wholesale customers as proposed by a commenter. We stated above our reasons for rejecting use of a contestable load analysis in the indicative screens, and we reject it for the DPT for the same reasons.

117. AARP and State AGs and Advocates argue that the Commission should consider evidence from actual market data in determining whether market power exists rather than rely on the results of the DPT to determine whether a seller has market power. We agree that actual market data is an important part of a determination of whether a seller may have market power. In this regard, we look at actual market data, both in the initial analysis and in ongoing monitoring of the EQR data. As the Commission stated in the April 14 Order, ''[a]s with our initial screens, applicants and intervenors may present evidence such as historical wholesale sales. Those data could be used to calculate market shares and market concentration and could be used to refute or support the results of the Delivered Price Test.'' [98] In addition, as part of our ongoing monitoring activities, we examine the EQR data in an effort to identify whether market prices may indicate an exercise of market power.

4. Other Products and Models

Comments

118. ELCON expresses concern over the entire horizontal market power analysis process: indicative screens, followed by DPT or mitigation for those that fail the indicative screens. ELCON notes that the evolution of these practices generally occurred in a series of highly contested proceedings, and did not benefit from the broader and more balanced review afforded by a generic rulemaking. ELCON states that its concern is that the practices unduly shift the burden of proof to potential victims of market power abuse. This concern would only be academic, ELCON continues, if the market structures were truly competitive and there were strong structural protections against the exercise of market power. But the hybrid nature of most regional markets, combined with inadequate infrastructure, creates an environment that discourages trust in market outcomes.[99]

119. Some commenters urge the Commission to allow different product definitions, *e.g.*, short-term power and long-term power, in the calculation of the indicative screens and the DPT. For example, NRECA argues that the Final Rule must require sellers to identify the relevant product markets, including the distinct products for which they seek market-based rate authority, and demonstrate that they lack market power in those product markets.[100] The Montana Counsel argues that the Commission's screens and DPT analysis models measure market power during certain test days for current time periods,[101] and that capacity that is available to make short-term energy sales may not be available for long-term, firm power sales. Thus, the Montana Counsel asserts that the Commission may not rely exclusively on short-term or spot markets to measure whether there are competitive long-term markets.

120. Other commenters remain divided over whether long-term power markets should be included in the market power analysis. PPL urges that long-term markets should not be considered in a market power analysis because of infeasibility and also because it violates the Commission's precedent that there is no long-term market power unless there exist barriers to entry.[102] In contrast, NRECA and TDU Systems state that long-term markets need to be analyzed in the market power analysis because monopolies will probably persist into the future for many consumers [103] and these consumers need protection. TDU Systems suggest using an installed capacity indicative screen for long-term markets.[104]

121. State AGs and Advocates and NASUCA suggest that the Commission adopt behavioral modeling, such as

[96] April 14 Order, 107 FERC ¶ 61,018 at P 111 (explaining that at less than 2,500 HHI in the relevant market for all season/load conditions there is little likelihood of coordinated interaction among suppliers in a market).

[97] July 8 Order at P 95–97 and NOPR at P 41.

[98] April 14 Order, 107 FERC ¶ 61,018 at P 112.

[99] ELCON at 4–5.

[100] NRECA at 16–18.

[101] Montana Counsel at 5–8.

[102] PPL reply comments at 2–3 and n.6, citing *Exelon Corp.*, 112 FERC ¶ 61,011 at P 136 (2005).

[103] NRECA reply comments at 11, TDU Systems reply comments at 5–7.

[104] TDU Systems reply comments at 9.

game theory, rather than structural analysis, because the latter cannot capture market power behavior.[105] NASUCA suggests that the Commission hold a technical conference to consider behavioral modeling. Duke disagrees with NASUCA's and others' calls for behavioral models, contending that they are theoretically complex and data-intensive and do not meet the prerequisite of being simple, easily understood and readily verifiable by the Commission.

Commission Determination

122. We will not generically alter the indicative screens or the DPT to allow different product analyses for short-term or long-term power as some commenters suggest. As the Commission has stated in the past, absent entry barriers, long-term capacity markets are inherently competitive because new market entrants can build alternative generating supply. There is no reason to generically require that the horizontal analysis consider those products that are affected by entry barriers. Instead, we will consider intervenors' arguments in this regard on a case-by-case basis.

123. We reject ELCON's contentions regarding the development of our horizontal market power analysis. While the screens and DPT criteria did arise out of specific cases, there have been numerous opportunities in this rulemaking for interested parties to express any concerns and propose alternatives, including technical conferences and numerous rounds of written comments. We believe that this rulemaking has given all interested parties ample opportunity to voice any and all options for revising the screens and DPT criteria and proposing alternatives, and has given us the opportunity to evaluate whether these tools remain appropriate. We conclude that they do.

124. Finally, we will not adopt the suggestion by some commenters that behavioral modeling be used in addition to, or in place of, the indicative screens and the DPT. Although game theory has been used in laboratory experiments and in theoretical studies where the number of players and choices available to players are limited, we do not consider it a practical approach for the volume of analyses we must perform, particularly since a vast amount of choices are available and many of those are unobservable. The data gathering and analysis burden imposed on sellers and the Commission would be overly burdensome and impractical.

[105] State AGs and Advocates at 29–30, NASUCA at 14–15.

5. Native Load Deduction

a. Market Share Indicative Screen

Commission Proposal

125. To reduce the number of ''false positives'' in the wholesale market share indicative screen, the Commission proposed in the NOPR to adjust the native load proxy for this screen. The Commission proposed to change the allowance for the native load deduction under the market share indicative screen from the minimum native load peak demand for the season to the average native load peak demand for the season. This change makes the deduction for the market share indicative screen consistent with the deduction allowed under the pivotal supplier indicative screen.

Comments

126. TDU Systems argue that the Commission provides no empirical evidence supporting this change—*i.e.*, no evidence of an excessive number of false positives produced by the Commission's current policy. TDU Systems also state that the Commission does not explain why it believes its current proxy ''results in too much uncommitted capacity attributable to the seller.'' [106] In particular, TDU Systems state that the Commission does not explain what factors it used to determine the appropriate level of uncommitted capacity to which it compared the current proxy.

127. APPA/TAPS agree, adding that the Commission proposal appears to be a results-driven effort to eliminate the need for some public utilities to submit a DPT.[107] APPA/TAPS argue that the Commission's ''false positives'' justification loses sight of the stakes involved in the market-based rate determination. They state that the price of a false positive associated with the initial screens will be the seller's submission of the DPT. APPA/TAPS argue that that price pales in comparison to the unreasonably high prices and market power exercise that can result from a false negative. According to APPA/TAPS, it is thus entirely appropriate for the Commission to take a closer look when a utility fails the initial screens, even when the Commission ultimately allows market-based rate authorization.[108]

128. In addition, APPA/TAPS state that, as well as lacking evidentiary basis, the proposed adjustment is not based on sound economic principles. APPA/TAPS argue that when the Commission originally adopted the native load proxy for the market share screen, it said the screen should reflect ''all of the capacity that is available to compete in wholesale markets at some point during the season.'' [109] APPA/TAPS state that now the Commission proposes to eliminate even more of the capacity that is available to compete at some point in the season by increasing the proxy to the average native load peak demand for the season.

129. APPA/TAPS further argue that adoption of the Commission's proposal would mean that the market-based rate screens would make no assessment of off-peak periods, even though the Commission has said that the market share screen is intended to measure market power during off-peak times.[110] They state that ''screens should examine market power for the on-peak and off-peak periods of the different seasons.'' [111]

130. Finally, APPA/TAPS argue that consistency across the two screens defeats the purpose of having more than one screen. The market share screen is intended to reflect capacity that could compete, including during off-peak periods. By contrast, the pivotal supplier screen is specifically intended to measure market power risks at system peak.

131. APPA/TAPS offer that if the Commission nonetheless believes some consistency is desired it can achieve it by using a native load proxy for the market share screen based upon the average minimum loads. Such a proxy would be consistent with the Commission's original intent of a screen that identifies ''all of the capacity that is available to compete in wholesale markets at some point during the season.'' [112]

132. Other commenters generally support the Commission's proposal to use seasonal average native load as the native load proxy for the market share indicative screen. Many state that the proposed native load proxy is a more accurate representation of native load obligations.[113] Several commenters

[106] TDU Systems at 13.

[107] APPA/TAPS at 68, citing *Acadia Power Partners LLC,* 111 F.E.R.C. ¶ 61,239 (2005), and *Kansas City Power & Light Co.,* 111 FERC ¶ 61,395 (2005), where the applying utilities failed the market share screen, but passed the pivotal supplier screen. In both cases, the company opted to submit a DPT, and after consideration, the Commission allowed the utilities to retain their market-based rate authority. *Acadia Power Partners, LLC,* 113 FERC ¶ 61,073 (2005); *Kansas City Power & Light Co.,* 113 FERC ¶ 61,074 (2005).

[108] APPA/TAPS at 68–70.

[109] APPA/TAPS at 69, citing April 14 Order, 107 FERC ¶ 61,018 at P 92.

[110] April 14 Order, 107 FERC ¶ 61,018 at P 72.

[111] APPA/TAPS at 70, citing Kirsch SMA Affidavit at 8–9.

[112] April 14 Order, 107 FERC ¶ 61,018 at P 92.

[113] *See, e.g.*, Ameren at 3, FirstEnergy at 4–5.

suggest excluding weekends and holidays from the proxy native load calculation because these periods are not representative of normal load hours.[114]

133. EEI argues that even with this proposed change, the generation capacity required by a utility to serve its native load is still being understated.[115] It states that utilities are required to meet the peak demands of their native load customers plus maintain a reserve margin for reliability purposes. This requirement directly determines the amount of generation capacity that a supplier can commit to the wholesale opportunity sales market. As such, EEI argues that the change proposed in the NOPR is a step in the right direction in terms of more accurately recognizing the amount of generation capacity required by a utility to meet native load requirements, but still understates the actual requirements.

134. EEI contends that from a generation planning perspective, no one with any expertise in that area doubts the native load proxy described in the April 14 Order underestimates the amount of capacity that a supplier needs to meet native load requirements and therein both overstates the amount of capacity that the supplier has to compete in the wholesale market as well as the supplier's market share. As a result of this overestimation of the capacity that a supplier would have to compete in the wholesale market, EEI contends that non-RTO vertically integrated utilities have failed the market share screen using the current native load proxy when many simply do not have market power.[116] EEI concludes that such a high number of ''e positives'' for market power that have occurred using the current proxy clearly supports the Commission's proposal to move the native load proxy to the average peak load in the season.

Commission Determination

135. We adopt the NOPR proposal to change the native load proxy under the market share indicative screen from the minimum native load peak demand for the season to the average of the daily native load peak demands for the season, making the native load proxy for the market share indicative screen consistent with the native load proxy under the pivotal supplier indicative screen.

136. In this regard, we find that the market share screen should be calculated using as accurate a representation of market conditions for each season studied as possible. We find that using the current native load proxy using the minimum native load level for the season does not provide an accurate picture of the conditions throughout the season.

137. We recognize that increasing the native load proxy will have the effect of reducing the market share for traditional utilities with significant native load obligations, and therefore may result in fewer failures of the wholesale market share screen for some sellers. However, we believe that such a result is justified. We are seeking a screen that provides a reasonably accurate picture of a seller's position given market conditions across seasons, so that we can eliminate those sellers who clearly do not have market power and focus our analysis on those who might. We believe that a native load proxy based on the average of peak load conditions is more representative, and thus more accurate, than a proxy based on extreme (*i.e.*, minimum) peak load conditions. We also believe that basing the native load proxy on the average of the peaks will make the screens more accurate in eliminating sellers without market power while focusing on ones that may have market power.

138. For sellers that contend that the proposed native load proxy will result in too many false positives, we note that under the existing native load proxy, fewer than 25 companies have been the subject of section 206 investigations since the April 14 Order. For entities that fear this change in native load proxy will lead to too many ''false negatives,'' (companies with market power passing under the indicative screens), we note that intervenors can always challenge the presumption of no market power. Moreover, no intervenor in this proceeding has pointed to specific companies that have passed the screens but still have market power.

139. We reject APPA/TAPS' argument that changing the native load proxy would result in the market-based rate screens making no assessment of off-peak periods. In fact, the native load proxy we approve here is based on the average of the native load daily peaks which also include low load days. The use of the average peak demand for the native load proxy provides for an assessment of all periods, peak and off-peak seasons, because such a proxy considers peak native load of each day in each season. Combined with the pivotal supplier screen that captures the annual peak conditions, we find that the two screens adequately capture market conditions over the year.

140. We also reject APPA/TAPS' argument that consistency across the two screens defeats the purpose of having more than one screen. The screens in and of themselves are inherently different methodologies in that the pivotal supplier screen considers whether the seller's generation must run to meet peak load, whereas the market share screen looks at the seller's size relative to other sellers in the market. We are looking for an assessment of the uncommitted seasonal capacity available to sellers to compete in wholesale markets and, as stated above, find that the average of the daily peak loads in a season more accurately reflects seller's commitments.

141. APPA/TAPS suggest that if we do raise the native load deduction, we only raise it to the average minimum for the season, rather than the average native load peak demand for the season. The intent of the wholesale market share screen is to assess market conditions during the season, not only during off-peak hours. APPA/TAPS is misplaced in its assertion that our original intent was for the market share screen to focus solely on off-peak conditions. In the April 14 Order we stated that ''by using the two screens together, the Commission is able to measure market power both at peak and off-peak times.''[117] Our statement simply recognizes that a seller with a dominant position in the market could have market power in the off-peak as well as the peak. Clearly the pivotal supplier analysis is designed to assess market power at peak times, but that does not imply that the wholesale market share screen is designed only to assess market power in the off-peak period.

142. Finally, we will not exclude weekends and holidays from the market share native load proxy. Since we adopt herein the use of an average peak demand for the native load proxy for the market share screen, the exclusion of weekends and holidays would inappropriately skew the results. Use of an average load addresses the issue of the variability between unusually high or low load days, is more objective, and easily applied. If weekends and holidays are excluded, only approximately 70 percent of total load hours would be accounted for. The

[114] *See, e.g.*, EEI at 17, PG&E at 6–7, Allegheny at 7–8, and Pinnacle at 34, both citing *Pinnacle West Capital Corp.,* 109 FERC ¶ 61,295 (2004). Several commenters disagree with the suggestion that weekends and holidays should be excluded from the native load proxy, stating that it is unsupported and, moreover, excluding these hours means that native load proxy ceases to be average. TDU Systems reply comments at 8–9, NRECA reply comments at 16–17.

[115] EEI at 24–25; *see also* Puget reply comments at 2.

[116] EEI reply comments at 24.

[117] April 14 Order at P 72.

average native load measure that includes weekends and holidays, and which we adopt, is truly an average of all load conditions.

b. Pivotal Supplier Indicative Screen

Commission Proposal

143. In the NOPR, the Commission proposed to retain the pivotal supplier screen's native load proxy at its current level of the average of the daily native load peaks during the month in which the annual peak day load occurs.[118]

Comments

144. Southern states that the pivotal supplier screen is conceptually sound; however, the manner of its current implementation reflects a significant flaw. In particular, Southern claims that the wholesale load (market size) is determined by the difference between the control area's needle peak demand and the average of the daily peaks in that peak month. Southern argues that it is not at all clear how or why this mathematical exercise (which in its opinion reflects an ''apples and oranges'' comparison) provides any meaningful measure of competitive wholesale demand during any relevant period.

145. For example, Southern continues, under some circumstances, all or a large portion of the wholesale load determined in this fashion could be the seller's own native load. Subtracting the average daily peaks in the peak month from a single needle peak to derive a ''proxy'' for competitive wholesale demand necessarily assumes that all of this difference is unsatisfied wholesale market demand that is subject to competition. Southern argues that this is not a valid assumption and the Commission has provided no reason to believe that it is. Southern therefore urges the Commission to abandon this aspect of the interim pivotal supplier analysis and instead use an estimate of actual wholesale load, rather than deriving it indirectly through an arithmetic exercise. For example, the seller's native load peak could be subtracted from the control area peak load on an ''apples to apples'' basis (for example, needle peaks, seasonal peaks, or average daily peaks) to derive, in Southern's view, a much better wholesale load proxy.[119] Southern asserts that such a reform would be relatively easy to implement and would yield much more meaningful results.[120]

146. NRECA disagrees with Southern's proposed modification to the pivotal supplier screen to use actual wholesale load, stating Southern provides no evidence that this modification would provide a more accurate estimate of the wholesale load than the current approach.[121]

Commission Determination

147. We retain the average daily peak native load as the native load proxy used in the pivotal supplier screen, as proposed in the NOPR, and we reject Southern's argument that our method of computing the native load proxy is unreasonable. Southern argues that because the wholesale demand is determined by subtracting the average daily peaks in the peak month from a single needle peak, the Commission is relying on an invalid assumption with regard to the wholesale demand during any relevant period. However, Southern's claim that our deduction of the average of the daily native load peaks from the needle peak is a ''mixing of apples and oranges'' ignores our reasoning in the April 14 Order:

> conditions in peak periods can provide significant opportunity to exercise market power. As capacity is utilized to meet demand there is less available to sell on the margin and often less competition. Only focusing on needle peaks that occur for a single hour and that are only known after the fact does not give an accurate reflection of the competitive dynamics of peak periods. As demand increases during peak periods, buyers and sellers are positioning themselves in the market with similar but incomplete information. Buyers are projecting their needs and trying to secure needed power, while sellers are negotiating to obtain the highest price for that power. With increasing demand, fewer units are available to serve anticipated peak needs and buyers bid to secure dwindling supply load increases. In addition, buyers must be prepared for the contingency that a unit will be forced out and they will need to purchase in a period of even greater scarcity.[122]

148. Further, both native load proxies provide an adequate solution to a complicated issue. Resources used to serve native load fluctuate over the course of the day and through the seasons. As the Commission stated in the April 14 Order, ''we recognize that not all generation is available all of the time to compete in wholesale markets and that some accounting for native load requirements is warranted here. However, wholesale and retail markets are not so easily separated such that a clear distinction can be made between generation serving native load and generation competing for wholesale load. Most utility generation units are not exclusively devoted to serving native load, or selling in wholesale markets.'' [123]

149. For these reasons we continue to believe that the average of the native load peaks in the peak month is a reasonable proxy for the native load deductions under this screen. Moreover, we also find that Southern's proposed method of estimating the actual wholesale load is inappropriate because it would artificially reduce the seller's share of that load. This is because Southern's methodology only deducts the seller's native load peak from the control area peak (not the native load peaks of any other sellers in the control area), leaving the seller with a disproportionately small share of the remaining market.

c. Clarification of Definition of Native Load

Commission Proposal

150. In the NOPR, the Commission expressed its belief that there has been some inconsistency in the way in which sellers have reflected native load in performing both the screens and the DPT analysis. Because the states are under various degrees of retail restructuring, the definition of native load customers has lacked precision. Accordingly, the Commission proposed to clarify that, for the horizontal market power analysis, native load can only include load attributable to native load customers as defined in § 33.3(d)(4)(i) of the Commission's regulations,[124] as it may be revised from time to time.

Comments

151. APPA/TAPS support the native load clarification, without providing additional explanation. A number of other commenters discussed the native load clarification in the context of defining retail contracts or provider of last resort (POLR) load as native load. PPL Companies request that this clarification not be adopted unless the Commission provides further clarification that an entity selling power to a retail customer under a long-term

[118] NOPR at P 44.

[119] Southern notes that this suggested calculation would still overstate the amount of wholesale load open to competition because some portion of that wholesale load would undoubtedly be covered with existing supply arrangements. It states that if it were required to net out the amount of wholesale load covered by those existing supply arrangements, a similar amount should be subtracted from the market resources deemed to be competing to serve the net wholesale load.

[120] Southern at 18–19.

[121] NRECA reply comments at 19–20.

[122] April 14 Order, 107 FERC ¶ 61,018 at P 91.

[123] *Id.* at P 67.

[124] 18 CFR 33.3(d)(4)(i) provides: Native load commitments are commitments to serve wholesale and retail power customers on whose behalf the potential supplier, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet their reliable electricity needs.

contract is able to deduct that capacity.[125]

Commission Determination

152. We will adopt the NOPR proposal that, for the horizontal market power analysis, native load can only include load attributable to native load customers as defined in § 33.3(d)(4)(i) of our regulations. We address the comments of PPL Companies' and others below in the ''Other Native Load Concerns'' section.

d. Other Native Load Concerns

Comments

153. Some commenters suggest alterations to the definition of native load or to the circumstances when contract capacity may be deducted from total capacity. One commenter recommends that POLR load be counted as native load.[126] Sempra argues that generators should be allowed to take native load deductions for power supplied to franchised utilities that divested their generation.[127] It argues that allowing such suppliers to claim native load deductions correctly assigns these obligations to the entities that actually commit the generation resources necessary to serve native load and results in a more accurate assessment of the suppliers' remaining uncommitted capacity. It notes that such sales may be for terms of less than one year, and that under the Commission's policy such suppliers cannot deduct those commitments as long-term firm sales. Sempra further points out that franchised utilities do not need a one-year or greater commitment to take a native load deduction. It concludes that marketers and other suppliers should thus be allowed to account for the native load commitments they undertake, regardless of the term of each underlying contract.[128]

Commission Determination

154. We will not adopt suggestions that sellers receive native load deductions for all their POLR contracts or for all contracts that serve utilities that have divested their generation. Even in cases where independent power producers (IPPs) serve what used to be franchised public utilities' native load, IPPs do not serve it under the same terms as those utilities.[129] Unlike franchised public utilities, IPPs may choose to exit the market once the contracts they sell power under have expired. However, we remind IPPs that POLR contracts with a term of one year or more may be deducted from total capacity under some circumstances. As the Commission explained in the July 8 Order, ''applicants may deduct 'load following' and 'provider of last resort' contracts for terms of one year or more under certain conditions. Specifically, we will allow sellers to deduct long-term firm load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation. The seller's contractual peak load obligation under the contract should be used as the capacity adjustment in the pivotal supplier analysis and the seasonal baseline demand levels served under the contract should be used as the adjustments in the market share analysis. The residual capacity will be considered available for sales in the wholesale spot markets and treated as uncommitted capacity.'' [130] Also, in response to PPL Companies, we note that long-term (one year or more) firm contracts that cede control may always be deducted from total capacity.

155. We will allow IPPs to deduct short term native load obligations if they can show that the power sold to the utility was used to meet native load. We agree with Sempra that allowing such suppliers to claim native load deductions correctly assigns these obligations to the entities that actually commit the generation resources necessary to serve native load and results in a more accurate assessment of the suppliers' remaining uncommitted capacity, and that such sales may be for terms of less than one year. Under our current policy such suppliers cannot deduct those commitments as long-term firm sales, whereas franchised utilities do not need a one-year or greater commitment to take a native load deduction.

6. Control and Commitment

Commission Proposal

156. The Commission noted in the NOPR that uncommitted capacity is determined by adding the total capacity of generation owned or controlled through contract and firm purchases less, among other things, long-term firm requirements sales that are specifically tied to generation owned or controlled by the seller and that assign operational control of such capacity to the buyer.[131] The Commission further stated that long-term firm load following contracts may be deducted to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase that will be used to meet the obligation even if such contracts are not tied to a specific generating unit and do not convey operational control of the generation.[132]

157. Noting that contracts can confer the same rights of control of generation or transmission facilities as ownership of those facilities, the Commission stated that if a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens. The capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility.[133]

158. In the NOPR, the Commission stated that in recent years some owners have outsourced to third parties pursuant to energy management agreements the day-to-day activities of running and dispatching their generating plants and/or selling output. The Commission noted that the agreement may, directly or indirectly, transfer control of the capacity. The Commission expressed concern that under such third-party agreements, there may be instances where control of capacity has changed hands, but this capacity has not been attributed to the correct seller for the purposes of the generation market power screens.[134]

159. In cases examining whether an entity is a public utility, the Commission has examined the totality of the circumstances in evaluating whether the entity effectively has control over capacity that it manages.[135] Likewise, in providing guidance regarding events that trigger a requirement to submit a notice of change in status, the Commission has

[125] PPL Companies at 14–17.

[126] Drs. Broehm and Fox-Penner at 11–12.

[127] Sempra reply comments at 4–5.

[128] PSEG Companies in their reply comments also make similar arguments about native load that are noted above in the ''Control and Commitment of Generation'' section.

[129] *See* 18 CFR 33.3(d)(4)(i) for the definition of native load.

[130] *See* July 8 Order, 108 FERC ¶ 61,026 at P 66.

[131] NOPR at P 46.

[132] *Id.*

[133] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority,* Order No. 652, 70 F. R. 8253 (Feb. 18, 2005), FERC Stats. & Regs., Regulations Preambles 2001–2005 ¶ 31,175 at P 47, *order on reh'g,* Order No. 652–A, 111 FERC ¶ 61,413 (2005).

[134] NOPR at P 48.

[135] *D.E. Shaw Plasma Power, L.L.C.,* 102 FERC ¶ 61,265 at P 33–36 (2003) (D.E. Shaw); *R.W. Beck Plant Management, Ltd.,* 109 FERC ¶ 61,315 at P 15 (2004) (Beck).

indicated that, to determine whether control has been acquired, sellers should examine whether they can affect the ability of capacity to reach the relevant market.

160. The Commission asked in the NOPR whether, in the interest of providing greater certainty and clarity regarding the determination of control, it should make generic findings or create generic presumptions regarding what constitutes control. In particular, the Commission sought comment on whether any of the following functions should merit a finding or presumption of control and, if so, on what basis: directing plant outages, fuel procurement, plant operations, energy and capacity sales, and/or credit and liquidity decisions.[136]

161. Alternatively, rather than focusing on these discrete functions, the Commission asked if it should establish a presumption of control for any entity that has some discretion over the output of the plant(s) that it manages. The Commission asked whether such an approach would promote greater certainty. The Commission also asked, if it adopted such a presumption, how it should address instances where discretion over plant output may be shared between more than one party.[137]

162. The Commission proposed to clarify that, in the event it adopted any such presumptions, an individual seller could rebut the presumption of control on the basis of its particular facts and circumstances. In addition, the Commission proposed to clarify that an entity that controls generation from which jurisdictional power sales are made is required to have a rate on file with the Commission. If the rate authority sought is market-based rate authority, then that entity is subject to the same conditions and requirements as any other like seller.[138]

163. The intent of the Commission's proposals was to provide greater certainty and clarity as to the treatment of capacity that is subject to energy management agreements and outsourcing of functions so that the capacity is properly reported (and studied) and to make clear that any entity to which control is attributed must receive the necessary authorizations under the FPA in order to provide jurisdictional services.[139]

a. Presumption of Control

164. As an initial matter, most commenters support the Commission's desire to provide greater clarity and certainty regarding the determination of control.[140] In this regard, many commenters express concerns that attributing generation capacity to sellers that do not necessarily control that generation may result in the seller falsely appearing to have market power and ultimately result in unnecessary mitigation. Commenters also express the need for the determination of control to be consistent for both the market-based rate authorizations and the change in status filings.

165. However, most commenters also oppose the Commission's proposal to establish generic findings or generic presumptions regarding what constitutes control, arguing that such findings must be made on a case-by-case basis. Others suggest a rebuttable presumption that control lies with the owner unless specific facts indicate otherwise.

i. Fact Specific Determinations

Comments

166. Various commenters argue for a fact specific determination of control.[141] For example, Alliance Power Marketing, a supplier of energy management services, argues that a case-by-case approach provides increased certainty for generators and asset managers who relied upon Commission precedent in developing their current arrangements.[142]

167. Several commenters state that they have some sympathy with the Commission's desire to provide certainty and clarity in this area, however, they do not agree that there should be generic presumptions regarding the indicia of control. One commenter argues that details of each contract vary, depending upon parties and circumstances involved as well as on conditions in the market place, and therefore it must be reviewed and evaluated with care.[143] This commenter suggests that an individual seller should be obligated to submit its contracts to the Commission for review, and allowed to present its case on the basis of its particular facts and circumstances.

168. Similarly, APPA/TAPS believe that the Commission is correct to assign capacity to a seller for purposes of running the screens/DPT; however, they point out that generic findings or presumptions would be helpful only if the particulars of a contract aligned with the factual assumptions underlying a presumption. Otherwise, they state that a presumption could produce wrong results.[144] APPA/TAPS suggest that any arrangement that could create opportunities for sellers to coordinate their behavior with other competitors should be reported and that as part of the seller's assigning control over long-term contracts for purposes of the screens/DPT, the Commission should require a seller to submit the relevant contracts with the market-based rate application or triennial update and identify the contractual provisions that support the seller's control determinations.[145] APPA/TAPS suggest that marketing alliances or joint operating agreements can affect a seller's market position and should be considered in the determination of control.[146]

169. Powerex argues that clarity is particularly important as the new market manipulation rule makes it unlawful ''to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading.'' [147] In this regard, Powerex urges the development of a single principle or set of principles that need to be met to establish control over an asset. Powerex argues that the development of such principles will help take the guesswork out of compliance and provide greater certainty for the market, as compared to a laundry list of possible contract types. Powerex states that the control principle should focus on physical output as opposed to financial terms, since it is physical output that addresses the Commission's physical withholding concerns and relates to the agency's market screens.[148]

170. EEI, EPSA, and Reliant argue that the Commission should continue to look at the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market.[149]

171. NYISO states that based on its experience in the administration of bid-based markets, what matters in the control of a plant is the ability to determine or significantly influence (a)

[136] *NOPR* at P 49.

[137] *Id.*

[138] *Id.* at P 50.

[139] *Id.*

[140] *See, e.g.,* Constellation at 18; EEI reply comments at 25; Financial Companies at 4; FirstEnergy at 5; Pinnacle at 4; Powerex at 7; SCE at 2.

[141] *See, e.g.,* Constellation at 18; Duke at 24; EPSA at 38; PPL at 9 and reply comments at 11; APPA/TAPS at 76.

[142] Alliance Power Marketing reply comments at 7.

[143] Drs. Broehm and Fox-Penner at 6–7.

[144] APPA/TAPS at 76.

[145] *Id.* APPA/TAPS further note that confidentiality concerns can be addressed with appropriate protective orders.

[146] APPA/TAPS at 77 and 89.

[147] Powerex at 7 (quoting 18 CFR 1c.2(a)(2)).

[148] Powerex at 8.

[149] *See, e.g.,* EEI at 19; EPSA at 37–38; Reliant at 5–6; SoCal Edison at 9.

The levels of the bids from the plant, and (b) the level of output from the plant. Accordingly, the Commission should focus directly on these critical facts, rather than creating presumptions based on indirect indicia of an ability to control these key competitive parameters. NYISO claims that plant engineering or technical operations may be outsourced without conferring an ability to control price or output, so that the outsourcing is not of particular competitive significance. If, however, an entity could determine or significantly influence bids or output, then it would be reasonable for the Commission to place a burden on that entity to demonstrate that it is not in a position to benefit from a possible exercise of market power. NYISO claims that if more than one party is in a position to exercise control over bids or output, then both such parties should have the burden of rebutting this presumption. NASUCA concurs.[150] Because of the fact-specific nature of these issues, the NYISO endorses the Commission's proposal to allow individual sellers to rebut the presumption on the basis of their particular facts and circumstances.[151]

172. Westar argues determinations of control over generating plants are essential elements of the negotiated risk sharing arrangement in virtually every energy management contract and that the Commission should not change its precedent absent clear evidence of market uncertainty or a finding that the established guidelines are inappropriate.[152]

173. Southern suggests that the approach taken in Order No. 652, where the Commission provided an illustrative list of contracts and arrangements that involve changes of control, is reasonable.[153]

Commission Determination

174. As discussed in the sections that follow, the Commission concludes that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. No single factor or factors necessarily results in control. The electric industry remains a dynamic, developing industry, and no bright-line standard will encompass all relevant factors and possibilities that may occur now or in the future. If a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens.[154]

175. Though we note the widespread support among commenters for the Commission's effort to provide greater clarity and certainty regarding the determination of control, there are differing points of view as to what circumstances or combination of circumstances convey control. These circumstances vary depending on the attributes of the contract, the market and the market participants. Thus, we conclude that it would be inappropriate to make a generic finding or generic presumption of control, but rather that it is appropriate to continue making our determinations of control on a fact-specific basis.

176. We agree with commenters such as Powerex and Westar that the Commission should rely on a set of principles or guidelines to determine what constitutes control. This has been our historical approach and we find no compelling reason to modify our approach at this time. Accordingly, as suggested by EEI, EPSA and others, we will consider the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market. Our guiding principle is that an entity controls the facilities when it controls the decision-making over sales of electric energy, including discretion as to how and when power generated by these facilities will be sold.[155]

177. With regard to suggestions that we require all relevant contracts to be filed for review and determination by the Commission as to which entity controls a particular asset (*e.g.*, with an initial application, updated market power analysis, or change in status filing), we will not adopt this suggestion. Under section 205 of the FPA, the Commission may require any contracts that affect or relate to jurisdictional rates or services to be filed. However, the Commission uses a rule of reason with respect to the scope of contracts that must be filed and does not require as a matter of routine that all such contracts be submitted to the Commission for review. Our historical practice has been to place on the filing party the burden of determining which entity controls an asset. As discussed below, we will require a seller to make an affirmative statement as to whether a contractual arrangement transfers control and to identify the party or parties it believes controls the generation facility. Nevertheless, the Commission retains the right at the Commission's discretion to request the seller to submit a copy of the underlying agreement(s) and any relevant supporting documentation.

ii. Rebuttable Presumption Regarding Ownership

Comments

178. MidAmerican argues that the Commission should adopt a presumption of control based on physical ownership of the generation (as adjusted for long-term sales or purchase power agreements). MidAmerican states that it is physical ownership that typically determines which entity controls the output of the generation and determines its ability to reach relevant markets. While many entities may have partial control over a unit's output, it is the owner that is most likely to affect market power.[156]

179. Morgan Stanley states that as a general rule, when assessing market power, the Commission should specifically adopt a rebuttable presumption that the entity that owns[157] the generation asset controls the generation capacity.[158] This presumption would shift if the asset owner relinquishes to a third-party the final decision-making authority over whether a unit runs (*i.e.*, if the third-

[150] NASUCA reply comments at 15 (quoting NYISO at 6).

[151] NYISO at 5–6.

[152] *See, e.g.*, Westar at 27–28.

[153] Southern at 23 (citing Order No. 652, FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,175 at P 83.

[154] NOPR at P 47–48 (citing July 8 Order, 108 FERC ¶ 61,026 at P 65.)

[155] Order No. 652, FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,175 at P 18.

[156] MidAmerican at 4 and 6–7.

[157] Morgan Stanley states that consistent with Commission precedent, the generation owner would not include entities that have a ''passive'' ownership interest where, due to the nature of the interest, the interest holder does not have the right or ability to direct, manage, or control the day-to-day operations of jurisdictional facilities. Citing *D.E. Shaw*, 102 FERC ¶ 61,265, at 61,823 (2003) (noting that passive owners may possess certain consent or veto rights over fundamental business decisions in order to preserve their financial investment, including, but not limited to, the right to grant or withhold consent regarding: (1) Material amendments to an LLC agreement under certain, specified circumstances; (2) issuance of new interests senior to the then-existing member interests in an LLC entity; (3) adoption of a new LLC agreement (or other operative or constituent documents) in connection with mergers, consolidations, combinations, or conversions in certain instances; (4) appointment of a liquidator (but only if the managing member of the LLC does not appoint one); and (5) assignment of investment advisory contracts under certain circumstances); *GridFlorida LLC*, 94 FERC ¶ 61,363, at 62,332 (2001).

[158] Morgan Stanley would define final control over physical output as resting with the market participant that, under normal operating conditions, can override all other entities on the decision of whether to dispatch the generation unit or that can otherwise hold an entity accountable for a dispatch decision. It submits that such authority typically rests with the generation owner. Morgan Stanley at 4.

party can trump the asset owner's dispatch instruction, then the third-party has control over whether the capacity reaches the market). Morgan Stanley states that such final decision-making authority would include authority to schedule outages.[159]

180. FirstEnergy proposes that where a generation owner is a public utility under Part II of the FPA, the Commission should adopt a rebuttable presumption that such owner controls all of the generating capacity that it owns.[160] FirstEnergy asserts that even where another entity is responsible for day-to-day operation of a generating unit, the generation owner generally will retain managerial discretion over the operation of the unit and over the sale of power from that unit into the market.[161]

181. A number of commenters argue that jointly-owned plants should be assigned based on percentage of ownership.[162] For example, Pinnacle states that, in the Southwest region, the joint ownership of base-load generating plants is the norm, and there is typically one party that has operational control over the facility. However, if the Commission refines the criteria for assigning generation to an entity based on factors such as directing plant outages, fuel procurement, and plant operations (or similar factors), there is concern that jointly-owned generation may be attributed in whole to each of the owners if there is joint decision-making on such factors (*e.g.*, if such decisions are made through a consortium of utilities forming a plant's joint operating committee) and result in unintentional double counting. Pinnacle also raises a concern that where joint plant owners appoint one of the joint owners to operate the plant, the entire plant will be attributed to the operator, rather than being attributed to each of the joint owners in shares. According to Pinnacle, the Final Rule should clarify that capacity of jointly-owned plants operated by one of the owners will be assigned to each joint owner based on its percentage interest.[163] Pinnacle states that the current rules under the interim screens with regard to assigning generating capacity to an entity appear to be workable.[164]

182. Many other commenters raise concerns about double counting in cases of shared control.[165] For example, with regard to shared facilities, FirstEnergy states that control of the plant should be attributed to the entity that is deemed to own the energy supplied from the plant. FirstEnergy offers that, if circumstances arise in which discretion over plant output is shared among more than one party, the Commission should permit the affected parties to resolve between themselves the entity to which capacity available in the unit will be attributed. FirstEnergy concludes that if the Commission adopts a regional approach to updated market power analyses, the Commission will be able to monitor those circumstances in which specified generation capacity is attributed to the wrong market participant.[166]

Commission Determination

183. With regard to the suggestion that we adopt a rebuttable presumption that the owner of the facility controls the facility, our historical approach has been that the owner of a facility is presumed to have control of the facility unless such control has been transferred to another party by virtue of a contractual agreement. We will adopt that approach. Accordingly, while we do not specifically adopt a rebuttable presumption that the owners control the facility, we will continue our practice of assigning control to the owner absent a contractual agreement transferring such control.

184. We note that the Commission has developed precedent regarding the contractual arrangements that can transfer control. In these cases, the Commission has stated that control refers to arrangements, contractual or otherwise, that confer control of generation or transmission facilities just as effectively as they could through ownership.[167] The capacity associated with contracts that confer operational control to an entity other than the owner thus must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility, when performing the generation market power screens.[168]

185. With regard to FirstEnergy's suggestion that the affected parties make a determination regarding the entity to whom capacity available in the generating unit will be attributed in order to avoid any unwarranted double counting in the attribution of control,[169] the Commission agrees that this is a constructive and appropriate approach. However, although we wish to avoid double counting as a general matter, the Commission will not rule out the possibility of double counting in circumstances where it is unclear what entity has control. For example, if different parties could control dispatch decisions under various circumstances, to err on the conservative side, the Commission may attribute generation to more than one seller for the purposes of the horizontal analysis.

186. To determine whether there are contracts transferring control to a seller seeking market-based rate authority, similar to the requirements for change in status filings,[170] the Commission will

[159] *See also* Financial Companies at 6.

[160] FirstEnergy similarly argues that there should be a rebuttable presumption that generation capacity purchased by an electric utility from a Qualified Facility (''QF'') as a result of a mandatory power purchase requirement established pursuant to the Public Utility Regulatory Policies Act (PURPA), 16 U.S.C. 824a–3(a), will be attributed to the seller rather than the purchaser. FirstEnergy argues that in many cases, the purchaser has little, if any, discretion over the dispatch of such units or the price at which energy is purchased.

[161] In its reply comments, PPL disagrees stating that, in assessing the entity that should be deemed to control capacity, whether assessing a contract to sell capacity or an asset management contract, the Commission should ask which party can benefit from an exercise of market power with regard to the supply at issue. PPL asserts that the flaw in FirstEnergy's proposal is that when a firm obligation to sell power is in effect, the seller cannot benefit from exercising market power with regard to the MWs sold pursuant to that firm obligation. Likewise, a buyer that can count on delivery of firm power is the ultimate decision-maker as to its resale. The seller will have to buy replacement power (at the prevailing market rate) if its expected source is not available, and therefore cannot benefit from withholding that amount of power. Thus such an approach would overstate one counter party's controlled capacity and understate the other's. PPL reply comments at 11–13.

[162] *See*, *e.g.*, Duke at 25.

[163] Pinnacle at 4–5. *See also* MidAmerican at 6–7.

[164] EEI agrees that in such a situation, if both owners have input on how and where the capacity is sold, then the asset should be allocated based on ownership percentages. EEI at 20.

[165] *See*, *e.g.*, Alliance Power Marketing reply comments at 8–9; Constellation at 6; MidAmerican at 6; PG&E at 8.

[166] FirstEnergy at 7–8.

[167] *Citizens Power and Light Corp.*, 48 FERC ¶ 61,210 at 61,777 (1989). *See also Bechtel Power Corp.*, 60 FERC ¶ 61,156 (1992) (finding that an entity that was contractually engaged to provide operation and maintenance services was not an ''operator'' of jurisdictional facilities because the entity did not ''operate'' the facilities at issue but rather, in essence, was functioning merely as the owner's agent with respect to the operation of the jurisdictional facilities); *D.E. Shaw*, 102 FERC ¶ 61,265 at P 33–36 (finding that a power marketer's ''investment adviser'' affiliate was a public utility where it had sole discretion to determine the trades to be entered into by the power marketer, as well as the power to execute the contracts, and therefore operated jurisdictional facilities rather than acted as merely an agent of the owner); *R.W. Beck*, 109 FERC ¶ 61,315 at P 15 (finding R.W. Beck Plant Management, Ltd. (Beck) was a public utility subject to the FPA in connection with its activities as manager of public utility Central Mississippi Generating Company, LLC because Beck effectively governed the physical operation of certain jurisdictional transmission and interconnection facilities and served as the decision-maker in determining sales of wholesale power).

[168] NOPR at P 47–48 (citing July 8 Order, 108 FERC ¶ 61,026 at P 65).

[169] FirstEnergy at 7.

[170] *See Calpine Energy Services, L.P.*, 113 FERC ¶ 61,158 at P 13 (2005) (sellers making a change in status filing to report an energy management agreement are required to make an affirmative statement in their filing as to whether the agreement

require sellers when filing an application for market-based rate authority or an updated market power analysis, to make an affirmative statement as to whether any contractual arrangements result in the transfer of control of any assets, including whether the seller is conferring control to another entity or obtaining control of another entity's assets. Moreover, in addition to requiring such affirmative statements as to whether any contractual arrangements result in the transfer of control of any assets,[171] the Commission will require sellers, when filing an application for market-based rates, an updated market power analysis, or a required change in status report with regard to generation, to specify the party or parties they believe has control of the generation facility and to what extent each party holds control.

187. We understand that affected parties may hold differing views as to the extent to which control is held by the parties. Accordingly, we also will require that a seller making such an affirmative statement seek a ''letter of concurrence'' from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing. Absent agreement between the parties involved, or where the Commission has additional concerns despite such agreement, the Commission will request additional information which may include, but not be limited to, any applicable contract so that we can make a determination as to which seller or sellers have control.

188. With regard to Pinnacle's concern regarding joint plant owners appointing one of the joint owners to operate the plant, we reserve judgment as a general matter. However, we understand that there may be situations where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners. Under these circumstances, it may be reasonable to allocate capacity based on ownership percentages. Such a determination should be made on a case-specific basis.

189. We remind sellers that in performing the horizontal market power analysis all capacity owned or controlled by the seller must be accounted for. In this regard, we expect that sellers, in performing such market power analyses, will clearly identify all assets for which they have control, or relinquished control, through contract.

iii. Energy Management Agreements

Comments

190. Most commenters state that energy management agreements and the functions listed in the NOPR (directing plant outages, fuel procurement, plant operations, energy and capacity sales, and/or credit and liquidity decisions) should not be presumed to convey control. Financial Companies state that a generic presumption of control by energy managers will ''chill a seller's willingness to provide energy management services.'' [172] Others suggest that the Commission should not adopt such a presumption and, in the alternative, should consider the specific aspects of an agreement. Additionally, some commenters request clarification on contract terms that are widely used in energy management agreements and may or may not convey control.

191. Sempra and financial entities argue that the Commission should not adopt a presumption that energy management agreements confer control over generating capacity.[173] They state that energy management and comparable agreements do not convey unlimited discretion and should not shift the presumption of control away from the entity that has final authority to dispatch the physical output of the plant.

192. Constellation agrees that the Commission should focus on whether an energy manager may make decisions about physical operation without final authority from a plant owner.[174]

193. Westar expresses concerns that the NOPR's invitation to consider ultimate control to reside with any entity that has some discretion over the output of a plant would invite confusion and undercut the Commission's declared objective to provide greater certainty and clarity in this area.[175] Alliance Power Marketing also expresses concern that a presumption that some discretion constitutes control will discourage innovation in the market, particularly with regard to option contracts and third-party arrangements.[176]

194. Alliance Power Marketing differentiates between asset/energy managers acting purely as agents and those that do not meet the legal definition of agents, suggesting that a market facilitator meeting the criteria of an agent should be exempt from attribution of control. The agent criteria identified by Alliance Power Marketing are: (1) The entity holds legal indicia of an agent's role; (2) the entity is neither a market participant nor an affiliate of a market participant; (3) the entity has limited, if any, financial stake in power market outcomes; and (4) the entity is subject to supervision or control in its activities on behalf of its principals.[177] Alliance Power Marketing submits that agents do not control generation if they are acting on behalf of their clients, do not assume the risk of transactions, and never take title to power. Constellation notes that the Commission has previously recognized that an agent who is acting subject to the direction of the owner should be not found to have control of a facility.[178]

195. Financial Companies disagree with Alliance Power Marketing's differentiation. They caution the Commission about imposing overly restrictive limitations on which entities qualify as agents or independent contractors and recommend that the Commission reject Alliance Power Marketing's proposal and suggest instead that ultimate decision-making authority is most relevant whether or not an agent is or is not a market participant.[179]

196. In contrast, NASUCA submits that the Commission should presume that energy management agreements convey control when energy managers can control generation output or the price or quantity of service offered.[180] Even more specifically, NASUCA recommends that the Commission reject formulations that would cloak market power of energy managers who control or affect electricity pricing, or the pricing of critical cost components such as fuel. Instead the Commission should adopt a rule that at a minimum encompasses the exercise of control over prices, bids, or output, including the ability to affect the cost of fuel and other inputs to generation.[181]

Commission Determination

197. After careful consideration of the comments, the Commission will not adopt a presumption of control regarding energy management agreements or the functions outlined in

at issue transfers control of any assets and whether the agreement results in any material effect on the conditions that the Commission relied upon in the grant of their market-based rate authority).

[171] Such a statement should include contracts that transfer control to another party as well as contracts that transfer control to the seller.

[172] Financial Companies at 9.

[173] Sempra at 12–13; Morgan Stanley at 5–6; Financial Companies at 7–8 and reply comments at 3–5.

[174] Constellation at 18.

[175] Westar at 28.

[176] Alliance Power Marketing reply comments at 8–9.

[177] *Id.* at 10–11.

[178] Constellation at 20 (citing *Bechtel Power Corp.,* 60 FERC ¶ 61,156 at 61,572 (1992)).

[179] Financial Companies reply comments at 3–4.

[180] NASUCA reply comments at 13 (*citing* NYISO at 6).

[181] *Id.* at 15.

the NOPR.[182] We agree with commenters that energy management and comparable agreements do not necessarily convey unlimited discretion and control away from the entity that owns the plant. In this regard, as noted above, it is the totality of the circumstances that will determine which entity controls a specific asset.

198. Further, the Commission will not adopt a presumption of control in the case of shared discretion over the output and physical operation of a plant. The Commission is aware that varying degrees of discretion may be shared in some cases, and believes that the determination of control in these cases is best addressed on a fact-specific basis. As noted by Sempra, there may always be an element of discretion associated with the implementation of instructions or guidelines included in energy management agreements.[183]

199. With regard to Alliance Power Marketing's differentiation between asset/energy managers acting purely as agents and those that do not meet the legal definition of agents, and suggestion that ''a market facilitator meeting the criteria of an agent should be exempt from attribution of control,'' we find this differentiation in and of itself not determinative. Instead, consistent with our conclusion that the determination of control is appropriately based on a review of the totality of the circumstances on a fact-specific basis such that no single factor or factors necessarily results in control, it is the combination of the rights conveyed that determine control, not whether an entity considers itself to be an agent and not a market participant.

iv. Specific Functions and Contract Terms

Comments

200. With regard to specific functions and specific contract terms, many commenters do not believe that functions such as directing plant outages, fuel procurement, plant operations, energy and capacity sales, and credit and liquidity merit a presumption of control.

201. NYISO and FirstEnergy both suggest that the functions listed in the NOPR may be outsourced without conveying ultimate control. According to EEI, the list of functions described in the NOPR would not provide greater guidance.[184] Rather, EEI believes a focus on the ability to withhold will be more effective than establishing presumptions based on the functions described in the NOPR. In particular, EEI argues that establishing presumptions for these individual functions would be difficult, because often it would be a combination of various functions that would result in the ability to affect bringing the capacity to market.[185]

202. Duke believes that the Commission should avoid simplistic presumptions as to what constitutes control over resources for market power purposes and how and when specific generation should be imputed to market participants for purposes of the screen analysis. Duke argues that in a market power context, such determinations should be fact-driven and based on a pragmatic assessment of which party has the ability to withhold a specific amount of capacity from the market. For example, the Commission should not automatically impute control over capacity based solely on contract language that appears to convey some element of discretion over unit operation to a particular party, notwithstanding the absence of any real world ability for that entity to withhold that capacity from the market. Duke states that the Commission should recognize that the ability to economically or physically withhold output from the market rests with the party that makes the final determination of whether generation (energy and/or capacity) will be offered into the market. Even a purchaser with dispatch rights may not have the ability to withhold supply, if the capacity owner has the right to schedule energy when the purchaser chooses not to do so. Similarly, a party with a contractual right to capacity (as opposed to energy), even with a call option for energy priced at market, does not have operational control over energy. Duke states that any contract in which rights to the energy ultimately revert to the owner/operator or for which energy is available only at a market price leaves control in the hands of the owner/operator. According to Duke, there should not be a blanket presumption that certain types of commercial arrangements or contractual language imply control in all instances.[186]

203. PG&E argues that any presumptions about control over generation should be based on whether a seller controls the dispatch of energy (*i.e.*, can affect the ability of the capacity to reach the relevant market). This general presumption should cover all types of transactions and business arrangements, rather than trying to address every possible function. Such an approach will be more effective than establishing presumptions based on individual functions, as various factors may intersect or combine to provide this control. Relevant factors include authority over the use or provision of fuel to the plant.[187]

204. PPL expresses concern that any arrangement in which a gas supplier could receive the output of a gas-fired generator as payment for the gas it supplies to the generator, if it is the only supplier to that generator, may convey control. PG&E appears to agree, stating that authority over the use or provision of fuel to the plant is a relevant factor with regard to control.[188]

205. EEI also appears to agree that fuel ownership may result in a change in control of plant output when, in the context of what triggers a change in status filing, it states: ''The Commission should continue the current policy that changes in the ownership of fuel supplies in and of themselves need not be reported. Only if the change in ownership of inputs results in a change of control of the output of the plant should a change in status filing be required. If a public utility acquires fuel supplies, there is no need to notify the Commission, unless the business structure, like a tolling agreement, actually results in discretion over the plant output.'' [189]

206. Sempra states that the Commission has generally treated energy management agreements as tolling agreements and requests that the Commission acknowledge the differences between the two.[190] APPA/TAPS state that particularly under tolling arrangements, while the supplier of fuel may not be operating the plant, it controls the plants' production of energy for sale, thus affecting market outcomes.[191] Constellation argues that plant operations and sales of output are functions that may convey control, but notes that the variety of case-specific facts limits the benefit of a blanket presumption of control.

207. Commenters also request that the Commission provide guidance regarding other contract types and terminology

[182] NOPR at P 49.

[183] Sempra at 13.

[184] EEI reply comments at 25.

[185] EEI at 22.

[186] Duke at 24–25.

[187] PG&E at 7.

[188] *Id.*

[189] EEI at 21.

[190] Sempra at 11–12. According to Sempra, under energy management agreements, energy managers typically sell power according to instructions or guidelines provided by the owner, and the energy manager is compensated on a fee-basis. Sempra states that in the case of tolling agreements, the tolling party generally has complete discretion over sales of output and assumes risk of sales transactions with the owner typically receiving a flat compensation and retaining authority over when to operate the facility.

[191] APPA/TAPS at 90.

such as call option contracts (with liquidated damages), contracts that allow variance in volume or delivery point, QF contracts, RMR contracts, capacity contracts, and load obligations.[192]

208. Finally, EEI seeks clarification that energy only contracts over 100 MW for a term greater than one year that do not include rights to specific capacity are one type of contract that does not transfer control.

Commission Determination

209. In Order No. 652, the Commission provided a non-exclusive, illustrative list of contractual arrangements that are subject to the change in status filing requirement. The list includes agreements that relate to ''operation (including scheduling and dispatch), maintenance, fuel supply, risk management, and marketing [of plant output]. These types of arrangements have in some cases also been referred to as energy management agreements, asset management agreements, tolling agreements, and scheduling and dispatching agreements.'' [193] The Commission clarifies that the illustrative list included in Order No. 652 provides guidance with regard to new applications for market-based rate authority and updated market power analyses as well as to change in status filings.

210. With respect to requests for clarification of whether certain contractual arrangements transfer control (such as call option contracts; liquidated damages contracts; contracts that allow variance in volume, source, or delivery point; QF contracts; RMR contracts; capacity contracts; and load obligations), for the reasons stated above, the Commission declines to address particular contractual terminology in isolation. The label placed on a specific contract does not determine whether it conveys control. Such determination necessarily must be made on a fact-specific basis.

211. Similarly, with regard to EEI's request for clarification that energy-only contracts over 100 MW for a term greater than one year that do not include rights to specific capacity are one type of contract that does not transfer control, for the reasons stated above, the Commission declines to address such a specific contractual arrangement generically.

b. Requirement for Sellers To Have a Rate on File

Comments

212. Alliance Power Marketing questions the Commission's proposal to clarify that any entity that controls generation from which jurisdictional sales are made is required to have a rate on file. Alliance Power Marketing believes that this proposal appears more akin to an inquiry than a Proposed Rulemaking.[194] Pinnacle requests clarification as to whether a non-jurisdictional entity is required to have a rate on file if that entity is the operator of a facility jointly-owned by jurisdictional and non-jurisdictional entities.[195]

Commission Determination

213. With regard to comments concerning the Commission's statement in the NOPR as to the need for an entity that controls generation from which jurisdictional power sales are made to have a rate on file, the Commission is reiterating, not modifying, the existing obligation to make rate filings. Under section 205 of the FPA,

> every public utility shall file with the Commission * * * schedules showing all rates and charges for any * * * sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.[196]

Part II of the FPA defines a public utility as ''any person who owns or operates facilities subject to the jurisdiction of the Commission.'' [197] Any entity not otherwise exempted from the Commission's regulations that owns or operates jurisdictional facilities from which jurisdictional power sales are made is a public utility required to have a rate on file with the Commission, unless the Commission has determined that such an entity does not in fact have ''control'' over the jurisdictional facilities sufficient to deem it a public utility (for example, if its ownership is passive, or its operation of facilities is as an agent subject to the control of the owner of the facilities). For any entity that is a public utility, if its rate authority is market-based, then it is subject to the conditions of authorization by the Commission (including the requirement to demonstrate lack of generation market power by the submission of market screens as spelled out in the horizontal market power section of this Final Rule). If an entity is a public utility and making jurisdictional sales without having a rate on file, those sales may be subject to refund, and the entity may be subject to a civil penalty.[198]

214. In response to Pinnacle, we clarify that if an entity has control of a jurisdictional facility and that entity is making jurisdictional sales, it would be a public utility subject to the jurisdiction of the Commission and would be required to have a rate on file with the Commission. However, if an entity is specifically exempted from the Commission's regulation pursuant to FPA section 201(f), it would not be considered a public utility under the FPA and, accordingly, would not be required to have a rate on file.

7. Relevant Geographic Market

a. Default Relevant Geographic Market

Commission Proposal

215. In the NOPR, the Commission proposed to continue to use its historical approach with regard to the relevant geographic market. The Commission stated that the default relevant geographic market is the control area where the generation owned or controlled by the seller is physically located and each of the control areas directly interconnected to that control area (with the exception of a generator interconnecting to a non-affiliate owned or controlled transmission system, in which case the relevant market is only the control area in which the seller is located). The Commission also proposed to continue to designate RTOs/ISOs with sufficient market structure and a single energy market in which a seller is located and is a member as the default relevant geographic market. In such circumstances the Commission would not require sellers to consider the first-tier markets to such RTOs/ISOs as being part of the default relevant geographic markets. In addition, the Commission noted in the NOPR that its experience with corporate mergers and acquisitions indicates that the same RTOs/ISOs that the Commission has identified as meeting the criteria for being considered a single market for purposes of performing the generation market power screens have, at times, been divided into smaller submarkets for study purposes

[192] *See, e.g.*, EEI reply comments at 25; EPSA at 38; Financial Companies reply comments at 7; FirstEnergy at 6; Reliant at 5; Duke at 25; PG&E at 7–8; PowerEx at 9–13; PPL at 13; PPL reply comments at 13; PSEG at 13 and 18; Sempra reply comments at 4; SoCal Edison at 10; Southern Company at 23.

[193] Order No. 652, FERC Stats. & Regs. Regulations Preamles 2001–2005 ¶ 31,175 at P 83.

[194] Alliance Power Marketing at 16.

[195] Pinnacle at 5.

[196] 16 U.S.C. 824d(c).

[197] 16 U.S.C. 824(e).

[198] *Vermont Electric Cooperative, Inc.*, 108 FERC ¶ 61,223 (2004), *order on reh'g*, 110 FERC ¶ 61,232 (2005).

because frequently binding transmission constraints prevent some potential suppliers from selling into the destination market. Therefore, the Commission sought comment on its approach under the market-based rate program of considering the entire geographic region under control of the RTO/ISO, with a sufficient market structure and a single energy market, as the default relevant market. We asked whether the Commission should continue its approach of considering the entire geographic region as the default market for purposes of the indicative screens but consider RTO/ISO submarkets for purposes of the DPT.

Comments

216. With regard to the RTO/ISO market, several commenters state that, based on all the protections associated with structured RTO/ISO markets with Commission-approved market monitoring and mitigation, the Commission should continue its current approach of allowing the entire geographic region of an RTO/ISO to be the default relevant market for the horizontal market power analysis.[199] They state that retention of this standard will simplify preparation of market power analyses by sellers within qualified RTOs.

217. Several commenters as well urge the Commission not to consider RTO or ISO submarkets. Sempra states that it recognizes that RTOs are at times divided into submarkets, such as for purposes relating to corporate merger and acquisition analyses, but it submits that the Commission should not consider RTO or ISO submarkets when conducting a market power analysis. Sempra states that the use of submarkets will result in uncertainty, confusion, and increased litigation as to the geographic boundaries of the ''right'' submarket that should be analyzed. According to Sempra, sellers that operate in RTO and ISO markets currently know with certainty the relevant geographic market for purposes of regulatory obligations such as reporting relevant changes in status, and the use of submarkets will eliminate that certainty and will open the door to competing definitions of submarkets. Sempra states that the existence of internal transmission constraints does not justify breaking up RTOs and ISOs into submarkets for purposes of the Commission's market power analysis. Sempra states that notably, only RTOs and ISOs with sufficient market structure and a single energy market can be used as default geographic markets. These attributes allow RTOs, ISOs, and their members to adopt mechanisms, including local markets or mitigation, that address potential concerns about local market power resulting from transmission constraints.[200]

218. Similarly, EPSA, PG&E, PPL, ISO–NE, CAISO and NYISO support use of the entire RTO/ISO as the relevant geographic market where the RTOs/ISOs operate a single centralized market and generally where there are measures for monitoring and oversight.[201]

219. In addition, EPSA offers that changes to the size of markets can be addressed on a case-by-case basis by sellers or when an intervenor presents specific evidence supporting reduction of the relevant geographic market.[202] PG&E states that in the case of a single control area like CAISO, there is little rationale or basis to determine how to subdivide a control area. Where there may be intermittent congestion within certain areas, the control area as a whole has regional planning and monitoring, avoiding the need to subdivide. In addition, the empirical fact that most sellers make no effort to justify an alternate geographic market—whether larger or smaller—supports the control area as the appropriate measure.[203]

220. PPL states that if the Commission were to impose stringent market power tests based upon temporary transmission limitations beyond generators' control (*e.g.*, infrequent intra-control area transmission system limitations), the Commission could make worse an already tenuous financial situation for existing generators in such areas and continue to deter new generation investment. Defining a geographic market smaller than a control area may lead to high failure rates of the screens. PPL states that associated loss of market-based rate authority (if that is the remedy imposed by the Commission) could precipitate economic retirements of those needed generators.

221. Finally, Ameren suggests that, for purposes of the DPT, the relevant geographic market should be the applicable RTO/ISO footprint, just as it is for purposes of the indicative screens, unless the Commission already has found the existence of a submarket in the relevant portion of the RTO/ISO. In such cases, the Commission should give due consideration to any existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket. If the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider appropriate submarket-specific mitigation in connection with granting market-based rate authorization.

222. On the other side of the issue, several commenters urge the Commission to consider internal transmission constraints and possible submarkets within RTOs/ISOs. The California Board proposes that the Commission permit RTOs to identify submarkets within their control area, as needed, to help determine possible local market power. The California Board states that if the Commission develops or approves criteria which sellers may use to expand their geographic market, then the same criteria must be applicable in RTOs to limit the size of a geographic market. The New Jersey Board states that intervenors should be allowed to present evidence that the relevant geographic market is smaller (or larger) than the default RTO/ISO market and states that evidence of binding transmission constraints is relevant when examining horizontal market power.[204]

223. State AGs and Advocates state that almost any large default geographic market will have many transmission-constrained areas (load pockets) within it and that the Commission must require applicants for market-based rate authority to do a proper analysis of the degree of market power that is likely to be exercised by all sellers, including the applicants, in all relevant load pockets or transmission-constrained regions or subregions in which the sellers control generation capacity. They state that all load pockets must be considered as appropriate geographic markets whenever they exist.

224. APPA/TAPS state that the presumption of the RTO footprint as the default geographic market must be truly rebuttable, including rebuttals based upon evidence that the RTO itself treats an area as a separate market.[205] APPA/TAPS state that in practice, however, the presumption appears to be irrebuttable. They argue that if known load pockets such as WUMS (or, for example, the Delmarva Peninsula, Southwest Connecticut, or the City of

[199] Wisconsin Electric at 5–7, FirstEnergy at 8–9, PG&E at 8–9, Xcel at 13–14, and Allegheny Energy Companies at 4–6. In addition, Ameren states that the Commission also should consider expanding the default geographic region beyond the footprint of a single RTO/ISO where contiguous RTOs/ISOs have a common market (Amerem at 4–5).

[200] Sempra reply comments at 1–3.

[201] EPSA at 11–12, PG&E at 8–9, and NYISO at 1–2.

[202] EPSA at 11–12.

[203] PG&E at 8–9.

[204] New Jersey Board at 3–4.

[205] APPA/TAPS at 56–63.

San Francisco, among others) do not rebut the geographic market presumption, the rebuttable presumption effectively becomes irrebuttable. APPA/TAPS recommend that in advance of each region's market-based rate review, RTOs should provide market participants with transmission studies that reveal where binding transmission constraints arise so that those data can be used in addressing the proper relevant geographic market. In addition, APPA/TAPS state that in the § 203 context, the Commission has correctly found that transmission constraints lead to distinct geographic markets, at least when those constraints are binding. They submit that no reasonable basis exists to distinguish between the competitive analyses used to establish relevant geographic markets in the section 203 and the section 205 contexts.[206]

225. In response to APPA/TAPS, EPSA states that in cases where the Commission denied a seller's argument to change its relevant geographic market, the Commission carefully considered the positions of parties advocating a different market and simply found their arguments insufficient to warrant a modification to the market definition.[207] EPSA states that it cannot be said that a presumption is irrebuttable simply because the Commission has, to date, deferred to RTO/ISO mitigation mechanisms to this point.

226. With regard to non-RTO areas, APPA/TAPS states that while the control area provides a reasonable starting point, the Commission's obligation to base its market-based rate decision on ''empirical proof'' requires reliance on specific facts that demonstrate whether the relevant geographic market should be the control area, or a smaller or larger area. APPA/TAPS further state that, for non-RTO areas, the seller should affirmatively address whether the geographic market should default to the control area or whether a smaller or larger area is appropriate, and support that result with evidence. They add that intervenors should also be allowed to introduce evidence regarding the question.[208]

227. With regard to both RTO/ISO and non-RTO areas, several other commenters urge the Commission to consider changing its existing policy on the default geographic market. State AGs and Advocates state that the best policy would be to have no ''default'' market criteria, but to have each applicant for market-based rates determine on an analytical basis what market area makes the most sense for its circumstances based on the actual transmission constraints that it faces.[209] NRECA states that using individual control areas or RTOs as the default market for evaluating a transmission provider's market power fails to account for the binding transmission constraints and load pockets that have developed within those markets.[210]

228. Morgan Stanley states that it supports the Commission's practice of relying on control areas and RTO/ISO regions when assessing market power as the default markets, but believes the Commission may be missing instances of market power by failing to also review known events that can create narrower or broader markets. For example, Morgan Stanley states that the Commission acknowledges that binding transmission constraints and the existence of load pockets can cause considerable market power issues. Therefore, Morgan Stanley asserts that the Commission should indeed consider whether a seller may possess the ability to exercise market power in a portion of an otherwise competitive market. To enable the Commission to do so, sellers should address known constraints in their description of the relevant geographic market in their market power filings, particularly in markets for which they are the control area operator.[211]

229. The California Commission states that while it agrees that designating a relevant geographic area will reduce uncertainty to all market participants, designation of a static geographic market in a dynamic market may defeat the purpose of market certainty and may have unintended adverse consequences over time. For example, with the implementation of locational marginal pricing (LMP) in the CAISO control area, there will be many submarket areas known as local areas. This will trigger ''false negatives'' (*i.e.*, absence of market power even when there is market power) in a control area analysis. A seller may pass both screens and receive market-based rate authority when tested against the broader geographic control area, such as the entire CAISO control area market. However, the same seller may not pass the screens when tested against a particular sub-area or local area. Accordingly, the California Commission states that the Commission should be flexible in designating geographic areas to determine market power. The Commission should designate geographic areas by considering current and reasonably foreseeable regional developments, as the Commission currently does in merger cases following DOJ/FTC merger guidelines.[212] Similarly, the Commission should consider the presence or absence of market power due to continuous developments of major market events (*e.g.*, area outages, congestion due to new market developments, and the development of load) that can have significant impact as inputs in the market power screening calculation.

230. In contrast, EEI disagrees with those commenters that would require the seller in each filing to affirmatively address with supporting evidence whether the geographic market should default to the control area or RTO/ISO area. EEI states that this requirement would defeat the purpose of having default areas to expedite and simplify the market-based rate filing process, noting that it is more efficient for any affected party to have the right to challenge the selection of the default market, as exists under the proposed regulations.[213]

Commission Determination

231. The Commission will adopt in this Final Rule its current approach with regard to the default relevant geographic market, with some modifications. In particular, the Commission will continue to use a seller's balancing authority area[214] or the RTO/ISO market, as applicable, as the default relevant geographic market.[215] However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.

232. With regard to traditional (non-RTO/ISO) markets, our default relevant geographic market under both indicative screens will be first, the balancing

[206] APPA/TAPS at 61–62.

[207] EPSA reply comments at 9–11, citing APPA/TAPS at 56.

[208] APPA/TAPS at 53–62.

[209] State AGs and Advocates at 44–48.

[210] NRECA at 12.

[211] Morgan Stanley at 8.

[212] California Commission at 5–6.

[213] 213 EEI reply comments at 26–27.

[214] As we discuss fully below, the Commission will adopt the use of ''balancing authority area'' instead of control area. As a result we use hereon the term balancing authority area. In addition, even though commenters use the term ''control area'' we will use the term ''balancing authority area'' in our response.

[215] In addition, the Commission will continue to require sellers located in and a member of an RTO/ISO to consider, as part of the relevant market, only the relevant RTO/ISO market and not first-tier markets to the RTO/ISO.

authority area where the seller is physically located,[216] and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets).[217] We also clarify that if a transmission-owning Federal power marketing agency (*e.g.*, the Tennessee Valley Authority, Bonneville Power Administration) is the home or first-tier market to the seller, then that seller must treat that Federal power marketing agency's balancing authority area as a relevant geographic market and file market power analysis on it just as it would any other relevant market.[218] Under the indicative screens, we will consider only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant market. For non-RTO sellers, we adopt a rebuttable presumption that the seller's balancing authority area and each of its neighboring first-tier balancing authority areas are each relevant geographic markets.

233. Although a number of commenters oppose the use of the balancing authority area as the default geographic market in traditional markets, they have submitted no compelling evidence that our historical approach is inadequate or insufficient for the typical situation. Indeed, using balancing authority areas allows the Commission and public to rely on publicly available data provided for balancing authority areas that are relevant to the market-based rate analysis discussed herein. These data are accurate and generally available. We will, however, continue to allow sellers and intervenors to present evidence on a case-by-case basis to show that some other geographic market should be considered as the relevant market in a particular case.[219] We clarify that the seller must provide the Commission with a study based on the default geographic market, and we will allow sellers and intervenors to present additional sensitivity runs as part of their market power studies to show that some other geographic market should be considered as the relevant market in a particular case. This evidence would be an addition to the required study based on the relevant geographic market as referred to in this Final Rule.

234. We do not adopt the suggestion by APPA/TAPS that the seller should affirmatively address whether the geographic market should default to the balancing authority area. We believe that EPSA's argument that such a requirement would defeat the purpose of having default areas and add uncertainty into the market is more persuasive. By defining default geographic markets, we provide the industry as much certainty as possible while also providing affected parties the right to challenge the default geographic market definition and provide evidence in that regard.

235. With regard to RTO/ISO markets, we agree with many commenters that RTOs/ISOs with a sufficient market structure and a single energy market with Commission-approved market monitoring and mitigation provide strong market protections. As a general matter, sellers located in and members of the RTO/ISO may consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of completing their horizontal analyses, unless the Commission already has found the existence of a submarket.

236. Where the Commission has made a specific finding that there is a submarket within an RTO/ISO, we believe that the market-based rate analysis (both indicative screens and DPT) should consider that submarket as the default relevant geographic market. This is consistent with how the Commission has treated such submarkets in the merger context. For example, in some merger orders, the Commission has found that PJM–East, and Northern PSEG are markets within PJM;[220] Southwestern Connecticut (SWCT) and Connecticut Import interface (CT) are separate markets within ISO–NE;[221] and New York City and Long Island are separate markets within NYISO.[222] Accordingly, we conclude that sellers located in these RTO/ISO submarkets should not use the entire PJM, ISO–NE and NYISO footprints as their relevant geographic markets for purposes of the market-based rate analysis. Instead, they should use as the default geographic market for their market-based rate analysis the submarkets that the Commission already has found constitute separate markets in those RTOs/ISOs.

237. We agree with APPA/TAPS that if the Commission makes a specific finding that the relevant geographic market is one other than the balancing authority area or RTO/ISO geographic region, the Commission's finding should define the default market going forward. For example, if the Commission finds that a submarket exists within an RTO, that submarket becomes the default geographic market for all sellers that own or control generation capacity within that submarket.

238. To the extent that the Commission finds that a submarket exists within an RTO/ISO, intervenors or sellers can provide evidence to the contrary (*i.e.*, the submarket, like our other default geographic markets, is rebuttable). In addition, if a seller or intervenor argues that the seller operates in an RTO/ISO submarket and presents sufficient evidence to support that conclusion, we will consider those arguments even if the Commission has not previously found that a submarket exists.

239. As a general matter, because we recognize the arguments raised by commenters that defining default geographic markets (whether balancing authority area, RTO/ISO footprint or RTO/ISO submarket) may not be appropriate in all circumstances, on a case-by-case basis, we will allow sellers and intervenors to present additional sensitivity analyses[223] as part of their market power analysis to show that some other geographic market should be considered as the relevant market in a particular case. For example, sellers or intervenors could present evidence that the relevant market is broader than a particular balancing authority area. Sellers and intervenors may also provide evidence that because of internal transmission limitations (*e.g.*, load pockets) the relevant market (or markets) is smaller than the balancing authority area, RTO/ISO footprint or RTO/ISO submarket. We believe this is a balanced approach because it establishes a presumption that the Commission will in most cases rely on default geographic markets, while at the same time, the Commission will give sellers and intervenors the opportunity to argue that the facts of a particular

[216] For applications by sellers with no physical generation assets (such as power marketers) that are affiliated with generation asset owning utilities, we will continue to evaluate the affiliate generation owner's market power when evaluating whether to grant market-based rate authority to the power marketer.

[217] Where a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (*i.e.*, the balancing authority area in which the generator is located.).

[218] *See, e.g., Portland General Electric Co.*, 111 FERC ¶ 61,151 at P 7 (2005); Idaho Power Co., 110 FERC ¶ 61,219 at n.6, P 10 (2005); *Florida Power Corp.*, 113 FERC ¶ 61,131 at P 17 (2005).

[219] We note that the Commission itself may explore whether an alternative geographic market is warranted based on the specific facts and circumstances of a given case.

[220] *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61,299 (2005) (*Exelon*). We note that Exelon later terminated the merger.

[221] *Wisvest-Connecticut, LLC,* 96 FERC ¶ 61,101 (2001). The parties later withdrew their application under FPA section 203.

[222] *National Grid plc*, 117 FERC ¶ 61,080 (2006).

[223] These analyses should be in addition to, not in lieu of, the analysis based on the default geographic market.

case support the use of some other geographic area as the relevant market.

240. We also provide, as discussed further below, guidance regarding the type of analysis required to rebut the default geographic markets including default markets for balancing authority areas, RTO/ISO markets, and RTO/ISO submarkets.

241. In this regard, sellers can incorporate the mitigation they are subject to in RTO/ISO markets or RTO/ISO submarkets with Commission-approved market monitoring and mitigation as part of their market power analysis. For example, if a market power analysis shows that a seller has local market power, the seller may point to RTO/ISO mitigation rules as evidence that this market power has been adequately mitigated. We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated.

242. With respect to market concentration resulting within RTO/ISO submarkets, we will continue to consider existing RTO mitigation. The Commission will consider an existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket. For example, New York City will be treated as a separate default market for market-based rate study purposes. However, because it has existing In-City mitigation, we will assess whether any concerns over market power are already mitigated. We agree with Ameren that if the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider whether and, if so, to what extent appropriate submarket-specific mitigation is needed.

243. In response to APPA/TAPS' statement that in practice the presumption of the RTO footprint as the default geographic market appears to be irrebuttable, this is simply not the case. The Commission carefully considers the positions and evidence submitted by parties advocating a different geographic market. Although we may have found that arguments made in a particular case were unconvincing, or that market power was adequately mitigated by existing mitigation,[224] we did, and will continue to, provide the opportunity for sellers to rebut the presumption. Moreover, as discussed above, where the Commission has made a specific finding that there is a submarket within an RTO, that submarket (not the RTO footprint) becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.

244. In this proceeding, we have considered expanding the default geographic region of a single RTO/ISO where contiguous RTOs/ISOs may have a common market as suggested by Ameren and find that there is insufficient support to make a generic finding that any contiguous RTOs/ISOs form a single geographic market.

245. With regard to the California Board's proposal that the Commission permit RTOs to identify submarkets within their balancing authority area, as needed to help determine possible local market power, we agree that this is an appropriate approach. However, we note that this is neither a new nor a novel approach. The Commission has historically considered the views of RTOs/ISOs in this regard and will continue to do so. We note, however, that to the extent RTOs/ISOs believe there is a market power issue within their RTO/ISO, they should notify the Commission promptly and not wait for an application by an entity seeking market-based rate authority or a current seller submitting an updated market power analysis.

246. Finally, to avoid any possible uncertainty or confusion about the RTO/ISO submarket, we identify RTO/ISO submarkets that the Commission to date has found to constitute a separate market. The Commission found submarkets in the PJM market, PJM East and Northern PSEG.[225] *In Wisvest-Connecticut, LLC*, the Commission also found two submarkets, SWCT and CT in ISO–NE.[226] In *National Grid plc*, the Commission again found two submarkets, New York City and Long Island, in NYISO.[227] These RTO/ISO submarkets will be the default geographic markets for purposes of the market-based rate analysis.

b. NERC's Balancing Authority Area and Default Geographic Area

Commission Proposal

247. In the NOPR, the Commission noted that the North American Electric Reliability Corporation (NERC) no longer uses the designation of control area since it approved the Reliability Functional Model (Functional Model). The Commission sought comment as to whether or not the adoption of the NERC Functional Model should change the criteria for specifying the default relevant geographic market, and if so, in what way it should be specified and how readily available the relevant data is.

Comments

248. Several commenters state that since NERC no longer uses control area designations, and its Functional Model refers to ''balancing authority areas,'' the Commission should modify slightly its approach to default geographic markets by simply replacing the term ''control area'' with ''balancing authority area.'' They state that such a change will align the Commission's rules with NERC's Functional Model, thus helping to avoid confusion.[228]

249. NYISO states that the control area is a valid starting point for the analysis of market-based rates. NYISO states that under the most recent version of the Reliability Functional Model posted on the NERC Web site (version 3, April 21, 2006), the ''Balancing'' and ''Market Operations'' functions appear to correlate to the traditional notion of

[224] *See, e.g., Mystic I,* LLC, 111 FERC ¶ 61,378 at P 14–19 (2005) (rejecting challenge to use of ISO–NE market as the relevant geographic market on the basis that local market power mitigation is in place: ''[W]ithout specific evidence to the contrary, we are satisfied that ISO–NE has Commission-approved tariff provisions in place to address instances where transmission constraints would otherwise allow generators to exercise local market power and that these rules and procedures will apply in the NEMA/Boston zone within ISO–NE.''); *Wisconsin Electric Power Co.*, 110 FERC ¶ 61,340 at P 19–20, *reh'g denied*, 111 FERC ¶ 61,361 at P 13–15 (2005) (rejecting challenge to use of Midwest ISO market as the relevant geographic market on basis that local market power mitigation measures exist: ''The tighter thresholds in NCAs such as WUMS in the Midwest ISO, and the resulting tighter mitigation of bids, are local market power mitigation measures'' and should adequately address specific concerns regarding the possibility that Wisconsin Electric can exercise market power in the WUMS region). *Accord AEP Power Marketing, Inc.*, 109 FERC ¶ 61,276 (2004), *reh'g denied*, 112 FERC ¶ 61,320 at P 23–25 (2005), *aff'd, Industrial Energy Users-Ohio* v. *FERC*, No. 05–1435 (D.C. Cir. Feb. 16, 2007) (use of PJM footprint as relevant geographic market; noting existence of Commission–approved market monitoring and mitigation).

[225] *See Exelon*, 112 FERC ¶ 61,011 at P 122.

[226] The Commission stated that ''clearly, during periods when transmission becomes so constrained such that no additional imports from outside the region are possible and generators located inside the region are the only suppliers that can sell inside the region, the region should be defined as a separate relevant geographic market. Such is the case with SWCT and CT in this proceeding.'' SWCT was defined as the area inside the Southern Connecticut Import interface, and CT was defined as the area inside the Connecticut Import interface, which is essentially contiguous with the state of Connecticut itself. *Wisvest-Connecticut, LLC*, 96 FERC ¶ 61,101 at 61,401–02.

[227] In *National Grid plc,* 117 FERC ¶ 61,080 at P 26, the Commission used Sellers' HHI numbers for two of the NYISO submarkets (New York City and Long Island) to assess horizontal market power, and found screen failures in both submarkets under the economic capacity analysis. *Id.* at P 31.

[228] E.ON U.S. at 19, PNM/Tucson at 21, and Indianapolis P&L at 4–5.

a control area operator for purposes of assessing competitive markets. Thus, the adoption of the Functional Model would appear to create issues more of terminology than substance. NYISO states that, whatever the terminology, the process of defining geographic markets should focus on the area in which grid operations generally facilitate the ability of generators to compete in the scheduling and dispatch of resources, and the ability of loads to purchase from such resources.[229]

Commission Determination

250. With regard to the use of the Functional Model by NERC, we agree with commenters that the Commission should modify slightly its approach to default geographic markets by replacing the term ''control area'' with ''balancing authority area.''

251. A balancing authority area means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, and the balancing authority maintains load/resource balance within this area.[230] Similar to control area, a balancing authority area is physically defined with metered boundaries that we refer to as the balancing authority area. Every generator, transmission facility, and end-use customer must be in a balancing authority area.[231] The responsibilities of a balancing authority include the following: (1) Match, at all times, the power output of the generators within the balancing authority area and capacity and energy purchased from or sold to entities outside the balancing authority area, with the load within the balancing authority area in compliance with the Reliability Standards; (2) maintain scheduled interchange and control the impact of interchange ramping rates with other balancing authority areas, in compliance with Reliability Standards; (3) have available sufficient generating capacity, and Demand Side Management to maintain Contingency Reserves in compliance with Reliability Standards; and (4) have available sufficient generating capacity, Demand Side Management, and frequency response to maintain Regulating Reserves and Operating Reserves in compliance with Reliability Standards.[232] It is the interconnection and coordination between balancing authority areas that provides a foundation for the Commission to analyze transmission limitations and other transfers of energy and provides a reasonable measure of the relevant geographic market under typical circumstances.

252. The Commission adopts in this Final Rule ''balancing authority area,'' instead of ''control area.'' We believe that such a change will align the Commission's rules with NERC's Functional Model, thus helping to avoid confusion.

c. Additional Guidelines for Alternative Geographic Market and Flexibility

Commission Proposal

253. In the NOPR, the Commission proposed to continue to provide flexibility by allowing sellers and intervenors to present evidence that the market is smaller or larger than the default market. The Commission explained that when assessing an expanded geographic market pursuant to the horizontal analysis, it looks for assurance that no frequently recurring physical impediments to trade exist within the expanded market that would prevent competing supply in the expanded area from reaching wholesale customers. The Commission stated that any proposal to use an expanded market should include a demonstration regarding whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching the customers within the expanded market. The Commission proposed to require that such a demonstration be made based on historical data, and said it would require that a sensitivity analysis be performed analyzing under what circumstances transmission constraints would bind.

254. The Commission explained that it also considers whether there is other evidence that would support the existence of an expanded market, such as evidence that customers can access the resources outside of the default geographic market on similar terms and conditions as those inside the default geographic market. It stated that such evidence could be empirical or it could point to factors that indicate a single market. It noted that the Commission has previously stated that the operation of a single central unit commitment and dispatch function for the proposed geographic market would be an indicator of a single market, but that other evidence of a single market could include a demonstration that: There is a single transmission rate; there is a common OASIS platform for scheduling transmission service across separate control areas; or there is a correlation of price movements between the areas being considered as an expanded geographic market or other information regarding wholesale transactions in the proposed single market. The Commission stated that evidence of active trading throughout the proposed geographic market would also be considered. It stated that in determining whether two or more control areas are a single market it would weigh, on a case-by-case basis, all the factors presented. The Commission noted that once it has been established that historically there were no physical impediments to trade, there are several factors the Commission would consider, and no one factor would be dispositive. The Commission sought comment on this proposed guidance and, in particular, whether there are other factors it should consider when assessing a proposed expanded market and whether there are any factors that should be given more weight or are essential in determining the scope of the market. The Commission also asked whether it should apply the same criteria when determining whether the geographic market is smaller than the default geographic market.

Comments

255. A number of commenters agree that it is appropriate to provide sellers flexibility in presenting evidence that the appropriate geographic market is broader than the default geographic market.[233] Several state that greater Commission guidance is needed so that sellers wishing to argue for a broader market definition have clear objective criteria and can provide evidence that the Commission will find probative.

256. Puget submits that the examples listed in the NOPR provide some guidance but are still too general to be of use to a seller submitting a new market power study. It states that the Commission should: (1) Provide additional guidance on the levels of price convergence and trading activity across a proposed alternative market that will support a seller's filing; (2) be more specific regarding the level of transmission constraints that will preclude a finding of an expanded

[229] NYISO at 2–4.

[230] *See* ''Glossary of Terms Used in Reliability Standards,'' at *http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp.*

[231] *See* Basic Operating Functions and Responsibilities: A White Paper by the Control Area Criteria Task Force.*http://www.maac-rc.org/reports/documents/cactf_reliability_model_whitepaper_v2.pdf.*

[232] *See* Approved Reliability Standards. *http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp.*

[233] Indianapolis P&L at 5–6, Puget at 9–11, Ameren at 4–5, Duke at 23–24, and Avista at 5–7.

market; and (3) not rely heavily, if at all, on transmission operation factors—such as common OASIS or common unit commitment and dispatch—that are not necessarily indicative of a common market.[234]

257. Southern states that the Commission's proposed focus on evidence pertaining to frequently binding transmission constraints for purposes of considering a larger geographic market seems appropriate. However, Southern argues that the NOPR's apparent requirement of additional evidence (beyond the absence of transmission constraints) to support a larger geographic market is unnecessary. Moreover, Southern submits that evidence of a single unit commitment and dispatch function, a single transmission rate, and a common OASIS platform is not likely to exist in the absence of an RTO or ISO. Accordingly, making such evidence a requirement for a larger geographic market would render illusory the opportunity for expansion for non-RTO/ISO sellers.[235]

258. Avista agrees that the absence of these factors does not necessarily mean that a market contains impediments to trading or that wholesale customers are unable to secure supply from alternative sources. Avista supports the Commission's proposal to state what type of evidence demonstrates active trading throughout the proposed geographic market. Avista submits that a regional geographic market could and should be established based upon: (1) The presence of an actively traded liquid trading hub within the relevant defined market area; (2) transparent pricing information from that hub being widely available; and (3) the presence of extensive direct or single-wheel transmission access, both for sellers into the competitive hub market and for buyers' access to the hub market for purposes of serving load.[236]

259. Powerex supports the Commission's initial specification of evidence that may be used to support a demonstration of a broader or smaller geographic market. However, Powerex is concerned that the Commission's enumeration of relevant categories of evidence is at present a partial list, and is not sufficiently comprehensive to address the unique circumstances that are likely to be present in various regions. Powerex states that the Commission should clarify that additional types of evidence may also be used to support the propriety of a broader or smaller market definition.

260. One commenter states that the appropriate definition of the relevant geographic market can be (and very often will be) conditional—that is, when there are no binding transmission constraints on imports into the relevant control area, the relevant market appropriately encompasses a broader area than the default geographic market; and when transmission constraints into the control area are binding, the control area is the appropriate geographic market. Accordingly, sellers should be allowed (or encouraged) to present analytical results for several market definitions, dependent on the existence or nonexistence of binding transmission constraints, to sharpen the focus on when market power might be a real concern.[237]

261. APPA/TAPS generally agree that the factors set forth by the Commission for assessing whether an alternative geographic market is appropriate are reasonable, but urge that the factors be non-exclusive and non-prescriptive. In addition to the factors the Commission identified in the NOPR, APPA/TAPS suggest that a seller be allowed to point to any joint transmission planning and coordinated construction processes as evidence that the relevant market should be larger than its own control area.[238] APPA/TAPS state that a seller that is correctly advancing efforts to expand markets deserves to have that recognized and a seller that is not undertaking such efforts should live with the consequences of the resulting smaller market.

262. PPL states that if the Commission is to consider the potential existence of geographic markets smaller or larger than a control area, it should carefully consider the specific circumstances surrounding the control area of concern, and use an objective review process. That is, the Commission should consider these factors through the following means: (1) Evaluation of the historical frequency of, and times when, physical transmission constraints limit the ability to transmit power within and between control areas, RTOs, and other defined regions within which electricity system supply and demand are balanced in real-time; (2) consideration of correlations of electricity prices, and electricity price day-to-day changes, within and between control areas, RTOs, and other defined regions within which electricity supply and demand are balanced in real time; (3) reference to historical evidence of actual transactions (including swaps/exchanges, etc.) wherein power is delivered within, imported to, or exported from, control areas, RTOs and sub-regions of RTOs; and (4) consideration of operational paradigms for obtaining transmission services and the extent to which the system allows for transparent access to transmission services.[239]

263. Several commenters urge the Commission to provide flexibility by suggesting a trading hub for an alternative geographic market. E.ON U.S. and PNM/Tucson state that the Commission should take regional commercial patterns into account when evaluating proposals to use a larger or smaller market, and they support allowing a seller to present a market power analysis specific to a trading hub.[240]

264. Indianapolis P&L asks that the Commission clarify that sellers can propose different geographic definitions in their screen analyses. Indianapolis P&L states that the NOPR is unclear as to whether different geographic markets can be proposed for the indicative screen analyses or only for additional, ''second stage'' analyses, such as the DPT.[241]

265. Powerex seeks clarification on how the definition of ''home control area'' (the control area where the seller is located) applies to an entity that has small-volume contracts in multiple control areas remote from its physical location. Powerex asks whether contracts with third parties, to the extent they confer some level of ''control,'' create a multitude of home control areas. Powerex seeks additional guidance, including whether the answer to the question depends on the quantity of generation available under each contract, the level of control, whether the seller is affiliated with the transmission provider in that control area, or the remoteness of the contracted generation from the sellers' physical location.[242]

266. Duke requests clarification of whether first-tier markets, which are part of a larger RTO/ISO market (with an energy market that has central commitment and dispatch and Commission-approved market monitoring and mitigation) can be represented as the entire RTO/ISO market. For example, in the case of the Duke Energy Carolinas' control area, which is directly interconnected to the AEP transmission system, Duke queries

[234] Puget at 9–11.

[235] Southern at 24–25.

[236] Avista at 5–7.

[237] Dr. Pace at 15–16.

[238] APPA/TAPS at 54.

[239] PPL at 2–6.

[240] E.ON U.S. at 14–15, PNM/Tucson at 8–10.

[241] Indianapolis P&L at 5–6.

[242] Powerex at 13–17.

whether all of PJM would be the relevant first-tier market for purposes of determining the simultaneous import limitations into the Duke Energy Carolinas control area.[243]

Commission Determination

267. As an initial matter, we acknowledge the desire for the Commission to provide greater guidance to sellers wishing to argue for a broader or smaller market definition. We continue to believe that default geographic markets are adequate and sufficient for the typical situation. However, defaults may not be appropriate in all circumstances. Therefore, we will attempt to provide additional guidance and clarification to help inform market participants regarding the factors we believe are significant to consider when defining the market.[244]

268. First, we reiterate that reaching beyond the default geographic market in which an entity is located can mean addressing additional physical and other challenges than when trading within that market. When assessing an alternative geographic market, the Commission looks for assurance that no frequently recurring physical impediments to trade exist within the alternative geographic market that would prevent competing supply in the alternative geographic market from reaching wholesale customers. Any proposal to use an alternative geographic market (*i.e.*, a market other than the default geographic market) must include a demonstration regarding whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching customers within the proposed alternative geographic market. We will require that a demonstration be made based on historical data and that a sensitivity analysis be performed analyzing under what circumstances transmission constraints would bind. If the seller fails to show that there are no frequently binding constraints at these critical times, then the Commission may not consider other evidence of an expanded market since we regard this as a necessary condition that must be satisfied to justify an expanded market.

269. The Commission also considers whether there is other evidence that would support the existence of an alternative geographic market. In deciding whether customers may be considered as part of an expanded geographic market, the Commission will consider evidence that they can access the resources outside of the default geographic market on similar terms and conditions as those inside the default geographic market.

270. Any such evidence submitted to show that the seller's customers have access to resources outside of their balancing authority area at terms and conditions similar to those at which they can access resources inside the balancing authority area could be empirical or it could point to factors that indicate a single market. For example, the Commission has previously stated that the operation of a single central unit commitment and dispatch function for the proposed geographic market would be an indicator of a single market. However, there are other ways to demonstrate that two or more balancing authority areas are indeed a single market. For example, other evidence of a single market could include a demonstration that: there is a single transmission rate; there is a common OASIS platform for scheduling transmission service across separate balancing authority areas; or there is a correlation of price movements between the areas being considered as an expanded geographic market or other information regarding wholesale transactions in the proposed single market. Evidence of active trading throughout the proposed geographic market would also be considered.

271. In determining whether two or more balancing authority areas are a single market, the Commission would weigh, on a case-by-case basis, all relevant factors presented. As discussed above, there are several factors the Commission would consider once it has been established that historically there were no physical impediments to trade, and no one factor or factors would be dispositive. Rather, all factors will be considered and as a whole will indicate whether there exists a single market.[245]

272. With regard to Puget's request that the Commission provide additional guidance with regard to the levels of price convergence, trading activity, and transmission constraints that define a market, no such generic finding will encompass all possibilities and, therefore, in all instances define the market. Accordingly, we will not attempt to do so here.

273. We also reject Southern's contention that the Commission has somehow rendered ''illusory'' the opportunity for entities outside RTOs and ISOs to demonstrate a larger geographic market.[246] The examples provided by the Commission of ways an entity could demonstrate a larger geographic market were just that: examples.[247] The Commission does not require an entity proposing an alternative geographic market to provide evidence other than historical transmission access. Sellers and intervenors in both RTO/ISO and non-RTO/ISO markets may present any probative evidence based on historical data of transmission availability, wholesale sales, resource accessibility, and market prices.

274. In response to Indianapolis Power & Light's comments, we clarify that when a seller submits its screen analysis, it can also propose an alternative analysis based on the use of a geographic market larger than the default geographic market. However, such proposal should be made in addition to, not in lieu of, the screen analysis based on the default geographic market.

275. With regard to using trading hubs as alternative market areas, the Commission understands that numerous electricity trading hubs have emerged over the past few years. A trading hub is a representative location at which multiple sellers buy and sell power and ownership changes hands, typically with trading of financial and physical products. For physical trades, the hub may represent a specific delivery point or set of points. Currently only select trading hubs account for the majority of physical power trading although there remains the possibility that market demand could initiate trading hubs for each balancing authority area. In evaluating market power, however, trading hub data alone does not provide a foundation for the Commission to analyze transmission limitations and other transfers of energy. Moreover, with regard to trading hubs, the combination of physical and diverse financial products, the low barriers for

[243] Duke at 28.

[244] Although the following discussion generally refers to an expanded market (*i.e.*, arguing that two or more default geographic markets constitute a single market) the same guidance is applicable for arguing that the market is smaller than the default geographic market (*e.g.*, a load pocket).

[245] We agree with Powerex that the Commission's enumeration of relevant factors it would consider is not an exhaustive list. As stated above, no comprehensive list of factors captures all factors that could indicate a single market. Accordingly, the Commission will consider additional types of evidence that may be presented on a case-by-case basis.

[246] Southern at 25.

[247] Thus, we agree with Avista that expansion of the geographic market is not limited to only those instances where there is either: a single transmission rate; a common OASIS; or operation of a single central unit commitment and dispatch function.

entry of new participants, and the unlimited potential for resale of limited physical output may not provide a reasonable measure of the relevant geographic market under typical situations, as a balancing authority area does. Therefore, while trading data may be considered in the illustration of relevant price correlation or of liquid trading activity to demonstrate that two or more balancing authority areas are indeed a single market, the Commission will not allow use of a trading hub to define a relevant geographic market.

276. With regard to one commenter's suggestion that the Commission should allow (or encourage) sellers to present analytical results for several market definitions because the appropriate definition of the relevant geographic market can be conditioned on the existence or nonexistence of binding transmission constraints, the Commission agrees in principle. The Commission provides an opportunity for sellers who fail one or more of the initial screens to present a more thorough analysis using the DPT. As the April 14 Order states ''the [DPT] defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.'' [248] In addition, in the Merger Policy Statement the Commission stated that the flows on a transmission system can be very different under different supply and demand conditions (*e.g.* peak vs. off-peak). Consequently, the amount and price of transmission available for suppliers to reach wholesale buyers at different locations throughout the network can vary substantially over time. If this is the case, the DPT analysis should treat these narrower periods separately and separate geographic markets should be defined for each period.[249]

277. The Commission believes that the DPT can address the dynamic nature of markets. Under the DPT, the amount and price of transmission available for suppliers to reach wholesale buyers at different locations throughout the network during different season/load conditions (*e.g.*, peak vs. off-peak) can be analyzed. For example, an area may become constrained only during the highest load levels, in which case the relevant geographic market could differ across seasons, and separate geographic markets could be defined for each period. However, as discussed earlier, in an effort to provide as much regulatory certainty as possible, the Final Rule adopts as the default geographic market the balancing authority area or the RTO footprint, as applicable, but allows sellers or intervenors to propose alternative markets based on historical transmission and sales data.

278. We clarify in response to Powerex that sellers should do market power studies for each balancing authority area where they own or control assets (*i.e.*, should study all balancing authority areas where generation assets they own or control are located) regardless of the quantity or location of generation they control (subject to the terms adopted herein regarding Category 1 sellers). Also, to the extent a market power study is required, sellers should study each balancing authority area where they own or control assets regardless of whether the seller is affiliated with the transmission provider in that balancing authority area. The Commission also clarifies for Duke that if the first-tier markets for a seller (whether or not the seller is a member of the RTO) are part of a larger RTO/ISO market, all of the RTO/ISO market would be a relevant first-tier market for purposes of determining the simultaneous import limitations.

d. Specific Issues Related to Power Pools and SPP

Commission Proposal

279. In the NOPR, the Commission proposed to continue its practice of designating an RTO/ISO in which a seller is located as the default relevant geographic market if the RTO/ISO has sufficient market structure and a single energy market with Commission approved market monitoring and mitigation.

Comments

280. A number of commenters urge the Commission to consider power pools as geographic market areas. Midwest Energy claims that, ''under current Commission policy, sellers of power in RTOs/ISOs with a full-fledged single central commitment and dispatch system are allowed to treat the full RTO footprint as the relevant geographic market, thereby facilitating qualification for market-based rates. Sellers in a Commission-approved RTO without a single central commitment and dispatch system are relegated to a relevant market defined by their own control area.'' [250] Midwest Energy urges the Commission to consider changing its existing policy to create a presumption that the relevant geographic market for a Commission-approved RTO is the region covered by a single transmission tariff.[251] Alternatively, Midwest Energy states that the Commission could require, in addition to a regional tariff, the implementation of a Commission-approved market monitor and a centrally dispatched energy imbalance market. It states that these changes would allow sellers to treat the Southwest Power Pool (SPP) region as the relevant geographic market.

281. Westar states that the Commission should find that a transmission region with a single OATT, non-pancaked transmission rates, a common OASIS platform for scheduling transmission, and approved market monitoring (*e.g.*, SPP) presumptively qualifies as a single region for purposes of the market power screens. Westar states that although the NOPR identifies single unit commitment and/or centralized dispatch of generation to be an important characteristic of a regional market, the Commission has not always done so. For example, the Commission did not identify this as a defining characteristic when it accepted other RTOs/ISOs as a single region for market-based rate purposes, such as New England. The Commission also did not rely upon centralized dispatch in authorizing market-based power sales across the California, New York or PJM markets. Westar states that the Commission should find that SPP meets the criteria for a single market once its energy imbalance market (EIM) becomes operational.[252]

282. In its reply comments, Southwest Coalition disagrees with those commenters requesting that SPP qualify as a single geographic region for sellers in its region once its EIM is operational. Southwest Coalition states that Westar has not presented any evidence for the Commission to change course with SPP in this rulemaking. It asserts that SPP currently has underway a variety of market implementation proceedings, of which Westar is a party, through which the Commission can make a reasoned decision regarding SPP's status. As such, Southwest Coalition states that this generic rulemaking proceeding is not the appropriate vehicle for considering Westar's request. In addition, Southwest Coalition states that Westar's request represents an improper request for rehearing of the Commission's March 20, 2006 Order in

[248] *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018 at P 106.

[249] Merger Policy Statement, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,044 at 30,132.

[250] Midwest at 1–3.

[251] Midwest at 1–3, 4–8.

[252] Westar at 3–6.

SPP's market implementation proceeding. Southwest Coalition requests that, if the Commission were to consider Westar's request in this proceeding, the Commission should reject Westar's request for a Commission finding that SPP is a single geographic region for purposes of the Commission's market power screens.[253]

283. Puget argues that applying the control area default to utilities in the Pacific Northwest is arbitrary, and does not result in an accurate measurement of a seller's potential market power in the region's energy markets. According to Puget, the relevant geographic market for the purpose of measuring horizontal market power in the Pacific Northwest is the United States portion of the Northwest Power Pool, which is dominated by a transmission system operated by Bonneville Power Administration. Puget submits that many of the criteria outlined in the NOPR—particularly those addressing parallel price movements, single transmission rates, and active trading—are met in this geographic region. Utilities in the Pacific Northwest would like to have the opportunity to make a showing to the Commission that the relevant geographic market for measuring market power in their region is an area other than their home and first-tier control areas.[254]

Commission Determination

284. We decline to address whether additional regions of the country qualify as relevant geographic markets. Through this Final Rule, we set forth several examples of criteria that sellers can use in proposing an alternative geographic market. Individual sellers can challenge our default geographic market and provide evidence to support their proposal. Intervenors will have the opportunity to comment prior to the Commission rendering a decision.

e. RTO/ISO Exemption

Commission Proposal

285. In the April 14 Order, the Commission concluded that it would no longer exempt sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses, on the basis that requiring sellers located in such markets to submit screen analyses provides an additional check on the potential for market power.[255] The Commission did not address this point in the NOPR.

Comments

286. In their comments in this proceeding, Reliant, NRG and FirstEnergy urge the Commission to reinstate the exemption.[256] Reliant states that reinstating the exemption would be appropriate because real-time market monitoring by an independent market monitor consistent with Commission-approved rules and Commission-approved targeted mitigation address identification of market power concerns as well as mitigation of market power in those markets and, therefore, eliminate the value of any separate market power analysis submitted by an individual seller. Reliant states that Commission-approved market monitoring and mitigation provide the Commission with a better and more sophisticated picture of market power issues in RTO/ISO markets as compared to a seller's market power analysis, which looks only at market power at a fixed moment in time.

287. Reliant states that if the Commission decides not to reinstate the exemption, it is critical that the Commission continue to use RTO/ISO markets as the default geographic market for sellers with generation located in those markets. Reliant states that the key to the determination of relevant geographic markets is the extent to which sellers can compete in the defined market. RTO/ISO markets with centralized markets provide a platform for all sellers located in the pertinent RTO/ISO market to compete. Thus, Reliant states that it is entirely appropriate to consider such markets as the default market unless and until an intervenor can show that this is no longer appropriate (*e.g.*, due to transmission constraints).[257]

288. In its reply comments, PSEG states that while it believes that the RTO/ISO exemption would be warranted at least for regions with pervasive market monitoring unit (MMU) oversight such as PJM, it recognizes that some affected parties may not be comfortable with a blanket exemption. It suggests that the Commission's regulations should take account of the fact that the Commission has approved comprehensive MMU oversight of markets and that MMUs take their duties seriously and routinely exercise their authority. Accordingly, PSEG proposes that evidence of active MMU oversight supply the basis for obviating the need to conduct a market power study for a particular zone or sub-zone of an RTO or ISO.[258]

289. APPA/TAPS, in contrast, state that reinstating the RTO/ISO exemption would represent an abdication of the Commission's responsibilities.[259]

Commission Determination

290. The Commission declines the request that it reinstate the pre-April 14 Order exemption for sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses. The Commission will continue to require generation market power analyses from all sellers, including those in RTO/ISO markets. All sellers are required to receive authorization from the Commission prior to undertaking market-based rate sales, and as discussed herein, all new applicants for market-based rate authority are required to, among other things, provide a horizontal market power analysis. The first step for a seller seeking market-based rate authority is to file an application to show that it and its affiliates do not have, or have adequately mitigated, market power. Sellers can refer to RTO/ISO monitoring and mitigating as a factor. We believe that a single market with Commission-approved market monitoring and mitigation and transparent prices provides added protection against a seller's ability to exercise market power but cannot replace the generation market power analysis.

291. To address Reliant's concern, we note that, as discussed above, we will use RTO/ISO markets (including Commission findings with regard to RTO/ISO submarkets) as the default geographic market for the indicative screens for sellers with generation in those markets.

8. Use of Historical Data

Commission Proposal

292. The Commission proposed in the NOPR to retain the ''snapshot in time'' approach for the indicative screens, so that sellers are required to use the most recently available unadjusted 12 months' historical data. The

[253] Southwest Industrial Customer Coalition reply comments at 2–9.

[254] Puget at 9–11.

[255] 107 FERC ¶ 61,018 at P 186. The Commission had previously stated that all sales, including bilateral sales, into an ISO or RTO with Commission-approved market monitoring and mitigation would be exempt from the Supply Margin Assessment test and, instead, would be governed by the specific thresholds and mitigation provisions approved for the particular market. *AEP Power Marketing, Inc.,* 97 FERC ¶ 61,219 at P 176 (2001).

[256] Reliant at 6–7; NRG at 7; and FirstEnergy at 33.

[257] Reliant at 6–7.

[258] PSEG reply comments at 5–6.

[259] APPA/TAPS reply comments at 2–3.

Commission stated that historical data are more objective, readily available, and less subject to manipulation than future projections. The Commission proposed to continue to permit sellers to make adjustments to data that are essential to perform the indicative screens provided that the seller fully justifies the need for the adjustments, justifies the methodology used, provides all workpapers in support, and documents the source data.

293. However, the Commission proposed to allow, for the DPT analysis, sellers and intervenors to account for changes in the market that are known and measurable at the time of filing.[260] The Commission noted that this proposal mirrors the Commission's approach in connection with its merger analysis. Sellers and intervenors proposing known and measurable changes to be considered in the DPT analysis would bear the burden of proof for their adjustments to historical data. The Commission sought comment on whether the Commission should provide a limitation on the time period past the historical test period for which sellers can account for changes, what that time period should be, and how flexible or inflexible that limitation should be. In addition, the Commission sought comment on exactly what types of changes should be allowed and under what circumstances.

Comments

294. Various commenters generally support the Commission's proposal to use historical data for the indicative screens and allow known and measurable changes for the DPT.[261] Some suggestions made as to what should be considered known and measurable changes include: Allowing only changes that occur between updated market power analysis filings[262] and allowing only publicly available data or company information.[263] Powerex expresses concern that known and measurable changes may not be publicly available.[264] PG&E suggests that the Commission evaluate on a case-by-case basis whether the seller or intervenor can prove that the change is both foreseeable and reasonable. It says that the Commission should not impose a time restriction on such changes provided that the seller provides the necessary support for changes that it claims are known and measurable.[265]

295. A number of commenters suggest that sellers should be permitted to account for known and measurable changes in both the indicative screens and the DPT.[266] Southern states that the Commission ''should not * * * restrict the ability of parties to provide the Commission with the best possible information and analysis.''[267] Duke states that in all instances the objective should be to obtain the most accurate and timely assessment of the seller's ability to exercise market power under current market conditions.[268]

296. NRECA states that the screens should incorporate imminent changes and that an example of known and measurable changes that should be included in initial applications and triennial filings is the capacity freed up by expiring long-term contracts. It submits that these contracts will expire on a known schedule and, if the market is competitive, the seller should not be allowed to assume that the capacity will remain committed to the buyer.[269]

297. PPL argues that long-term contracts should retain the current definition as those expiring in one year or more, and recommends not considering contracts that take effect after one year but before the triennial update is due. It argues that buyers could withhold signing contracts and force a market power finding. PPL also notes that a notice of change in status must be filed at the expiration of contracts that increase the seller's capacity by 100 MW or more and that the Commission can initiate a section 206 investigation at that point if need be.[270]

Commission Determination

298. We will continue to require the use of historical data for both the indicative screens and the DPT in market-based rate cases. The indicative screens are designed as a tool to identify those sellers that raise no generation market power concerns and can otherwise be considered for market-based rate authority. Accordingly, the indicative screens are conservative in nature and not generally subject to debates over projected data, which may unnecessarily prolong proceedings and create regulatory uncertainty. However, in light of adopting a regional approach with regard to regularly scheduled updated market power analyses, we will require the use of the actual historical data for the previous calendar year. Requiring all sellers in a region to provide analyses using the same data set further enhances the Commission's ability to evaluate market power and identify any discrepancies between market studies.

299. After careful consideration of the comments received, the Commission will not adopt the NOPR proposal that the DPT analysis allow sellers and intervenors to account for changes in the market that are known and measurable at the time of filing. Instead, the Commission will adopt its current practice that sellers are required to use, in the preparation of a DPT for a market-based rate analysis, unadjusted historical data and, consistent with the above discussion, the Commission will require the use of the actual historical data for the previous calendar year. The Commission has stated that historical data are more objective, readily available, and less subject to manipulation than future projections.

300. We acknowledge that the Commission's approach in its merger analysis requires applicants and intervenors to account for changes in the market that are known and measurable at the time of filing. However, we find that the purpose of using the DPT in market-based rate proceedings is different from that in merger analysis. Intrinsically, a merger analysis is forward-looking to identify what effect, if any, there will be on competition if the proposed merger is consummated. Even though the Commission has the ability to reopen a merger proceeding under its section 203(b) authority, it is difficult and costly to undo a merger, so the Commission is cognizant of the need to analyze what might happen as a result of a proposed merger and put any necessary mitigation in place prior to consummation of the merger.

301. In contrast, the market-based rate analysis is a ''snapshot in time'' approach. When the Commission evaluates an application for market-based rate authority, the Commission's focus is on whether the seller passes both of the indicative screens based on unadjusted historical data. Likewise,

[260] *See* 18 CFR 35.13(a).

[261] *See, e.g.*, EEI at 23, PPL at 17–19; Powerex at 18–19.

[262] *See, e.g.*, Ameren at 6. Ameren proposes that if a seller chooses to rely on an historical period with no changes, the Commission should honor that choice and not allow intervenors to introduce suggested known and measurable changes. Conversely, if a seller proposes to adjust the historical period for certain known and measurable changes, Ameren states that the Commission should permit intervenors to introduce competing known and measurable changes. *Id.* at 6–7.

[263] Drs. Broehm and Fox-Penner at 12–13 (any adjustments to historical base year must be known and measurable at the time of filing; new capacity additions should only be accounted for if they are on-line or under construction).

[264] Powerex at 18–19.

[265] PG&E at 9–10.

[266] PG&E at 2; Southern at 25–26; Duke at 26; NRECA at 21–23.

[267] Southern at 26.

[268] Duke at 26.

[269] NRECA at 21–23. *See also* APPA/TAPS at 13–15.

[270] PPL reply comments at 3–4.

when a seller fails one of the screens and the Commission evaluates whether that seller passes the DPT, the Commission's focus is on whether the seller passes the DPT based on unadjusted historical data. The Commission's grant of market-based rate authority is conditioned, among other things, on the seller's obligation to inform the Commission of any change in status from the circumstances the Commission relied upon in granting it market-based rate authority. As such, the Commission's market-based rate program is designed to require sellers to report, and enable the Commission to examine, changes in facts and circumstances on an ongoing basis. Such a reporting requirement provides the Commission with ongoing monitoring in addition to its right to require any market-based rate seller to provide an updated market power analysis at any time. Accordingly, the market-based rate change in status reporting requirement allows the Commission to evaluate changes when they actually happen rather than relying on projections, making it unnecessary and redundant for the Commission to allow sellers to account for known and measurable changes in the DPT for market-based rate purposes. For these reasons and the reasons explained in the April 14 and July 8 Orders and existing Commission precedent, the Commission reaffirms that the indicative screens and DPT analyses should be based on unadjusted historical data.

9. Reporting Format

Commission Proposal

302. In the NOPR, the Commission proposed to require all sellers to submit the results of their indicative screen analysis in a uniform format to the maximum extent practicable and appended a proposed format. This format, provided in Appendix C of the NOPR, was intended to promote consistency and aid the Commission in the decision-making process. The Commission sought comment on this proposal.

Comments

303. Although only a few comments were received on this topic, those comments support the proposal to adopt a uniform reporting format for the indicative screens. APPA/TAPS suggest that the proposed uniform format should help all market participants, especially when assessing the filings of a number of public utilities as part of the proposed regional review process. APPA/TAPS state that the uniformity should also help the Commission analyze market-based rate filings on a consistent basis, thus increasing market participant confidence in those assessments.[271] Other commenters concur with the Commission's proposal for a uniform reporting format. They state that a uniform reporting format will increase consistency and thus aid the Commission in its decision making process.[272]

304. One commenter suggests formatting and presentation changes to the NOPR's Appendix C reporting form. These changes include creating sections for items such as the calculation of seller and market uncommitted capacity and rearranging some in a more logical fashion.[273]

Commission Determination

305. We will adopt the reporting format as proposed in the NOPR, maintaining the same order of items as in the form provided in Appendix C of the NOPR, but note that this form now appears as Appendix A of this Final Rule. We believe standardizing the submission format has benefits to all market participants. As noted, it appears that commenters as well are generally supportive of this proposal to require all sellers to submit the results of their indicative screen analyses in a uniform format.

306. Also, we will adopt many of the formatting changes suggested in the comments. The row letter will be the first column and a better delineation of sections will increase the comprehensibility of the form. The revised form can be found in Appendix A.[274]

10. Exemption for New Generation (Formerly Section 35.27(a) of the Commission's Regulations)

a. Elimination of Exemption in Section 35.27(a)

Commission Proposal

307. The Commission's regulations provide that any public utility seeking authorization to engage in market-based rate sales is not required to demonstrate a lack of market power in generation with respect to sales from capacity for which construction commenced on or after July 9, 1996.[275] In the NOPR, the Commission noted that when it established the exemption in Order No. 888 it indicated that it would consider whether a seller citing § 35.27(a) nevertheless possesses horizontal market power if specific evidence is presented by an intervenor.[276]

308. The Commission stated in the NOPR that although it remains committed to encouraging new entry of generation, it is concerned that the continued use of the § 35.27(a) exemption may become too broad and, over time, would encompass all market participants as all pre-July 9, 1996 generation is retired. Accordingly, the Commission proposed in the NOPR to eliminate the exemption in § 35.27(a) and to require that all new sellers seeking market-based rate authority on or after the effective date of the Final Rule and all sellers filing updated market power analyses on or after the effective date of the Final Rule must provide a horizontal market power analysis of all of their generation, whether or not it was built after July 9, 1996. Because the Commission allows a seller to make simplifying assumptions where appropriate and to submit a streamlined analysis, the Commission explained that any additional burden imposed on sellers by this reform would be minimal. In addition, the Commission anticipated that those entities that otherwise would have relied on the exemption would, in most cases, qualify as Category 1 sellers and therefore no longer be required to file updated market power analyses as a routine matter. The Commission sought comment on this proposal.

Comments

309. Many commenters support the Commission's proposed elimination of the § 35.27(a) exemption, stating that there should be a level playing field for market-based rate sellers so that all market participants would be required to perform the generation market power screens.[277] A number of commenters support the Commission's position that there is a valid concern that over time the exemption would encompass all generation as older generating units are

[271] APPA/TAPS at 35.

[272] Drs. Broehm and Fox-Penner at 12.

[273] Dr. Pace at 8–9.

[274] The ''Workpapers'' column is meant to provide an easy way to find sources and ensure that all submissions are properly sourced. Hence, the items in that column (*e.g.*, ''Workpaper 5'') were merely meant to be illustrative and do not require that information be submitted on specific workpapers or that workpapers be submitted in a particular order.

[275] 18 CFR 35.27(a). The regulation reads: ''Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

[276] NOPR at P 67.

[277] Progress Energy at 2; PG&E at 10; FirstEnergy at 9; TDU Systems at 2; New Jersey Board at 2; NASUCA at 7; Drs. Broehm/Fox-Penner at 13.

retired and new generation is built.[278] Several commenters state that the Commission correctly observes that the indefinite continuation of the exemption would ultimately result in the automatic grant of market-based rate authority to all sellers as pre-1996 generation is retired.[279] They further state that eliminating the exemption will not impose significant new burdens, deter new entry into a market, or create any unreasonable disincentive or impediment for the construction of future generating capacity.[280] Contrary to the assertions of several commenters, FirstEnergy states that the elimination would encourage merchant power developers to expand generation in markets where they do not already have a dominant position which, in turn, would dilute market power concerns in these markets.

310. NRECA and APPA/TAPS maintain that, despite EPSA's, Mirant's, and PPL's assertions to the contrary,[281] the Commission did not create the exemption as an incentive to encourage new generation investment.[282] APPA/TAPS elaborates further, agreeing with the Commission that many new entrants would qualify as Category 1 sellers and, therefore, would not have to submit updated market power analyses and that other entrants could make simplifying assumptions to demonstrate that they qualify for market-based rate authority.[283] These commenters contend that the benefits of eliminating the exemption far outweigh any added burdens to ensure that all market participants are treated equally and to ensure that rates for jurisdictional sellers are just and reasonable.[284]

311. In support of the elimination of the § 35.27(a) exemption, NASUCA acknowledges that under current procedures, if all the generation owned or controlled by an applicant for market-based rate authority and its affiliates in the relevant control area is new generation, such seller is not required to provide a horizontal market power analysis because of the exemption under § 35.27(a).[285] NASUCA asserts that under the current rule, there is no limit on the amount of post-July 9, 1996 generation that could be exempt from the Commission's analysis of market power. In addition, a commenter explains that the potential to exercise market power has no relation to whether generating plants were built before or after 1996.[286] ELCON suggests that generators that were built after July 9, 1996 are capable of exercising market power.[287] In addition, FirstEnergy points out that merchant power plant developers have begun to aggregate fleets of newer generating plants to which this exemption is applicable, and may now be able to exercise generation market power.[288] PG&E adds, ''in situations where all generation owned or controlled by an applicant and its affiliates in the relevant market is new generation, should they control sufficient generation, the applicants and its affiliates may freely exercise market power.'' [289] In addition, Morgan Stanley supports elimination of the exemption, stating that maintaining the exemption would have unintended consequences going forward.[290]

312. Among those who oppose elimination of the exemption, Constellation asserts that it would send an unfavorable signal to market participants that the rules may be changed with a retroactive effect, which in turn would deter investment.[291] Constellation also contends that the Commission offers no support and/or analysis to demonstrate its inference that older generating units will be retired in significant quantities to make a substantial difference to the screening analysis of any seller. PPL submits, among other ill-effects, that the elimination will deter investment in areas where there is a limited supply and the new entrant may be deemed pivotal. In addition, PPL contends that some sellers relied on the presumption that they would not need to demonstrate a lack of market power in financing, constructing, and operating their new power plants.[292]

313. EPSA opposes the elimination of the exemption under § 35.27(a). EPSA states that the electric industry needs incentives for new generation and does not need disincentives if capital is to be invested on a timely basis to meet future demand and enhance competition.[293] EPSA asserts that the exemption encourages the development of competitive supply outside of organized markets.[294] Similarly, NRG contends that the elimination of the § 35.27(a) exemption will delay and deter investment in load pockets. NRG also argues that eliminating the exemption runs counter to the Commission's policy of encouraging investment in electric power infrastructure to enhance reliability and market liquidity.[295]

314. In addition, EPSA argues that the purpose of the exemption was to encourage new generation investment by competitive suppliers, especially in areas of the country that are mostly dominated by utility-owned generation.[296] Specifically, EPSA explains that it is in these regions of the country where affiliated generation is largely treated as native load and, thus, is excluded from the market power analysis even though it represents most of the capacity in the region.[297] EPSA explains that, even if a small increment of competitive supply is introduced into the market, the analysis might detect market power when measured against relatively small existing generation. Therefore, without the exemption, a new competitive supplier would fail the test and would have to utilize cost-based rates.[298]

315. Allegheny argues that the Commission overlooks the reason why it initially adopted the exemption. Allegheny states that, in Order No. 888, the Commission determined that long-term generation markets are competitive.[299] Allegheny further argues that ''the Commission cannot 'gloss over' its prior reasoning without discussion, and without showing that there has been a fundamental change in facts and circumstances that have [sic] caused long-term markets to be no

[278] *See* PG&E at 10; APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[279] APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[280] *See* FirstEnergy at 10; APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[281] EPSA at 12–13; Mirant at 11; PPL at 19–20.

[282] NRECA reply comments at 11; APPA/TAPS reply comments at 16–17.

[283] *See* APPA/TAPS at 27.

[284] APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[285] NASUCA at 7.

[286] Drs. Broehm/Fox-Penner at 13.

[287] ELCON at 6.

[288] *See* FirstEnergy at 9–10.

[289] PG&E at 10.

[290] Morgan Stanley at 13–14.

[291] Constellation at 30.

[292] PPL at 19–20.

[293] EPSA at 12.

[294] EPSA reply comments at 6.

[295] NRG at 2.

[296] EPSA at 13.

[297] In its reply comments NASUCA disagrees, submitting that there are other regions where a seller with a fleet of newer exempted generating plants could exercise market power or bid the output strategically to drive prices up. NASUCA reply comments at 4–5.

[298] EPSA at 13.

[299] Allegheny at 8–9 (citing *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, FERC Stats. & Regs., Regulations Preambles, January 1991–June 1996 ¶ 31,036 at 31,657 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,048 (1997), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in part and rev'd in part sub nom.* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002)).

longer competitive.'' [300] PPL asserts that the Commission in Order No. 888 recognized the power that the opportunity of free entry has to eliminate market power concerns and stated that open access advancements removed structural impediments for new entrants competing with existing market participants.[301]

316. Mirant and EPSA expand on arguments that eliminating the exemption will deter investment. They argue that, when reserve levels are tight in a control area where the host utility has lost or forgone its market-based rate authority, a competitive supplier would have to weigh the risks as to whether the Commission would authorize it to make market-based rate sales if it were to build a new asset in that control area.[302] They contend that there is no incentive for a competitive supplier to build new generation if its sales will be mitigated at some level of cost-based rates.[303] In particular, Mirant explains that if a municipal utility issued a request for proposals (RFP) for 600 MW of power commencing in 2010 and terminating in 2020, with the current exemption competitive suppliers could bid on the RFP knowing that the supplier would be authorized to sell the output of its new generating station at market-based rates. However, Mirant asserts that if the exemption were eliminated, a supplier would have to get Commission approval for market-based rate sales prior to bidding on the RFP. [304]

317. Mirant disagrees with the Commission's contention that eliminating the exemption would not affect many sellers and that the cost of compliance would be minimal. Mirant states that five of its subsidiaries would have to file updated market power analyses if the exemption were eliminated because they own more than 500 MW in the relevant market or control area and would not qualify as Category 1 sellers. Mirant argues that its cost of compliance would increase because it would have to prepare four updated market power analyses, each costing $20,000 to prepare and file.[305] In its reply comments, APPA/TAPS state that Mirant's increased cost is paltry compared to the over $3.4 billion in generation revenues reported by Mirant in 2005, which APPA/TAPS suggest is in no small part due to Mirant's market-based rate sales.[306]

318. Some commenters contend that the Commission's concern that over time all older generation will be retired and the Commission will be unable to analyze sellers for market power is not a valid concern in the immediate or mid-term; they state that the most recent retirement announcements concern generation assets that were built in the 1940s and 1950s.[307] PPM and Allegheny argue that the Commission offers no evidence or observations to quantify the magnitude of future retirements.[308] Some commenters assert that, in order for this speculative concern to become realistic, the retirement of generating units that were constructed in the 1980s would have to become commonplace, and it will take decades for this situation to materialize. As such, they suggest that the Commission revisit this issue in 5 to 10 years rather than act prematurely.[309]

319. PPM suggests that, if the Commission wishes to limit the overall amount of generation that is exempt for purposes of conducting a horizontal market power analysis, an alternative approach would be to keep the exemption and phase in exempted units over time. Thus, units that were built after 1996 but before 1999 would lose the exemption in 2010, while facilities built in 2001 would lose it in 2015, and so on.[310]

Commission Determination

320. The Commission adopts the proposal set forth in the NOPR and eliminates the exemption provided in § 35.27(a). All sellers seeking market-based rate authority, or filing updated market power analyses, on or after the effective date of this Final Rule must provide a horizontal market power analysis for all of the generation they own or control. As a number of commenters recognize, over time the exemption would become too broad and would encompass all market participants as pre-July 9, 1996 generation is retired. In addition, we note that even assuming for the sake of argument that there are not a large number of retirements, the current exemption would allow sellers to grow unabated as load increases and could result in such sellers gaining a dominant position in the market without being subject to any horizontal market power analysis. Thus, continuing the exemption would result in unintended consequences where all sellers would be given an automatic presumption that they lack market power in generation. Accordingly, the Commission finds that eliminating the exemption in § 35.27(a) and requiring every new seller to submit a generation market power analysis will allow the Commission to ensure that the seller does not have market power in generation.[311]

321. We do not believe that this change will have an adverse effect on the majority of sellers that have previously relied on the § 35.27(a) exemption. The sellers that have taken advantage of the exemption will largely qualify as Category 1 sellers, and thus will be unaffected to the extent that they will not be required to file a regularly scheduled updated market power analysis. For those sellers seeking market-based rate authority for the first time (*e.g.*, building new generation facilities), and those that do not qualify as Category 1 sellers, there are several mechanisms or alternatives that can help to minimize the burden of submitting a horizontal market power analysis. For example, a seller, where appropriate, can make simplifying assumptions, such as performing the indicative screens assuming no import capacity or treating the host balancing authority area utility as the only other competitor.[312] We expect that, for most sellers, the cost of compliance and document preparation occasioned by the elimination of § 35.27(a) will not be burdensome. To the extent that there are greater costs for some sellers, we find that the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs. Equally important, the elimination of § 35.27(a) will place all sellers on the same footing. On this basis, we disagree with commenters that eliminating the exemption would send an unfavorable

[300] Allegheny at 9 (citation omitted).

[301] PPL at 20.

[302] Mirant at 11–12; EPSA at 13–14.

[303] EPSA at 13; Mirant at 12.

[304] Mirant at 11–12. Mirant elaborates: ''In calculating the pivotal supplier and market share screens, an applicant is allowed to deduct from its installed capacity the amount of capacity that is committed under a long-term sale, but the seller is presented with a Catch-22. The seller cannot enter into a long-term sales contract at market-based rates without prior Commission authorization, but the seller cannot pass the applicable indicative screens without deducting the amount of the capacity sold under long-term contract. Retaining the exemption eliminates this problem and is consistent with Commission precedent regarding competitive forward markets.'' *Id.* at 12.

[305] Mirant at 11.

[306] APPA/TAPS reply comments at 17.

[307] Mirant at 10; EPSA at n.2, citing for example: *http://pjm.com/planning/project-queues/gen-retirements/20060601-pjm-gen-retir-list-public-future.pdf.*

[308] PPM at 6; Allegheny at 8.

[309] EPSA at 15; Mirant at 10.

[310] PPM at 6.

[311] We note that the Commission may change its policy if it provides, as it does here, a reasoned analysis indicating that prior policies are being deliberately changed and the basis for that change. *E.g., B&J Oil and Gas* v. *FERC*, 353 F.3d 71 (D.C. Cir. 2004).

[312] *See* April 14 Order, 107 FERC ¶ 61,018 at P 69, 117.

signal to market participants and deter investment.

322. We also disagree with commenters that find our rationale for adopting the exemption in 1996 necessarily constrains our decision making at this time. In light of our experience over the past decade and our desire to have a more rigorous market-based rate program, combined with the concern that over time generation will be retired, we believe a more conservative approach for granting market-based rate authority is appropriate and will provide us a better means to ensure that customers are protected.

323. We find unpersuasive Mirant's concern that, if the § 35.27 exemption were eliminated, a seller would have to get Commission approval for market-based rate sales prior to bidding on an RFP. If Mirant is concerned that certain RFPs require, among other things, that all bidders have in place all regulatory requirements including any applicable market-based rate authority, we find that RFPs typically afford bidders ample opportunity to put together their bids and put in place any necessary regulatory approvals. In this regard, we note that if a potential seller wishes to participate in an RFP but does not have market-based rate authority, the seller can file for such authorization and request expedited treatment and the Commission will use its best efforts to process the request as quickly as possible.

324. With regard to the specific argument raised by Mirant, if a prospective seller wins an RFP, then the capacity would be counted as committed capacity, and therefore would not adversely affect the results of the seller's generation market power screen (which analyzes uncommitted capacity). If the entity loses the RFP, then it would not build the plant. In either case, the need for market-based rate authorization does not appear to discourage new investment by competitive suppliers as Mirant suggests.

325. Some commenters assert that the retirement of generating units that were constructed in the 1980s would have to become commonplace before the Commission's concern is realized that over time all older generation will be retired. Others contend that it will take decades for this situation to materialize. However, commenters have provided no evidence that the elimination of § 35.27(a) will create a regulatory barrier to new construction or otherwise depress the building of new generation facilities, and we need not wait for an inevitable adverse circumstance to materialize.

326. Finally, we will not implement PPM's suggestion that we retain the exemption and apply a phasing in approach whereby generating units would lose the exemption over time based on the date on which the units were built. Such an approach would create several ''classes'' of generation facilities which would result in confusion for both the Commission and market participants. This confusion would become more acute in situations where market participants may own a number of generating facilities located in the same balancing authority area or relevant geographic market, each of which may be considered a different ''class'' of generator in terms of filing horizontal market power analyses. Moreover, given the regional review and schedule for updated market power analyses discussed below in this rule, we believe that a phased-in approach would become overly problematic and unmanageable for market participants as a whole. Therefore, we will not accept PPM's suggestion.

b. Grandfathering

Comments

327. EPSA and Mirant suggest grandfathering units for which construction commenced between July 9, 1996 and May 19, 2006, the date of issuance of the NOPR, when generation owners were put on notice that the Commission was considering eliminating the exemption in § 35.27(a).[313] Constellation proposes that the exemption not be eliminated entirely but be limited to generation with construction that commenced on or after July 9, 1996, but before the effective date of the Final Rule in this proceeding.[314] Constellation and EPSA also contend that this would be consistent with the Commission's prior decision to grandfather from PJM's mitigation any generating units that were built in reliance on the post-1996 exemption.[315]

328. Although NASUCA agrees with the Commission's proposal to eliminate the new generator exemption, NASUCA raises a concern about the prospective treatment of sellers with generating plants built after July 9, 1996 that initially received market-based rate authority without any generation market power assessment. NASUCA notes that its understanding is that, ''the Commission would effectively ''grandfather'' the market-based rate status for owners of these newer power plants,[316] at least until the time of the next applicable triennial review, when a market power analysis would be required for continuation of market-based rate authority.'' [317] Specifically, NASUCA explains that a Category 2 seller who recently obtained market-based rate authority, could have up to three years of future market-based rate sales with no review of its horizontal market power, while any that fall into Category 1 would be exempted entirely from the triennial review process and thus ''grandfathered'' indefinitely and able to sell at market-based rates without passing any market power test. If this ''grandfathering'' is not intended, then, according to NASUCA, the Commission should clarify that new market power assessments must be made now for those sellers whose market power has never been reviewed.[318] Otherwise, NASUCA contends that their rates could be vulnerable to challenge because they are established solely on the basis of market price.[319]

Commission Determination

329. We will not adopt commenters' proposals with regard to the grandfathering of any generating units that were built relying on the exemption in § 35.27(a). As discussed above, we find establishing ''classes'' of generation facilities would result in confusion for both the Commission and market participants. In this regard, no

[313] EPSA at 15; Mirant at 13.

[314] *See* Constellation at 31; PPL reply comments at 20.

[315] Constellation at 31, citing *PJM Interconnection, LLC,* 110 FERC ¶ 61,053 at P 60–62 (grandfathering the exemption from mitigation for generating units for which construction commenced on or after the date the exemption became effective and before the date when PJM filed its proposal to eliminate the exemption for all generation units) (*PJM*), *order on reh'g,* 112 FERC ¶ 61,031 at P 38 (2005) (*PJM II*), *order on reh'g,* 114 FERC ¶ 61,302 (2006); EPSA at 16–17.

[316] NASUCA at 10 n.12, ''[T]he Commission would require that all *new* applicants seeking market-based rate authority on or after the effective date of the final rule issued in this proceeding, whether or not all of their or their affiliates' generation was built after July 9, 1996, must provide a horizontal market power analysis of their generation.'' *Citing* NOPR at P 71 (emphasis added).

[317] *Id.* at n.13, ''[W]ith regard to triennial reviews, the Commission's proposal to eliminate the section 35.27(a) exemption would require that, in its triennial review, a seller must perform a horizontal market power analysis of all of its generation regardless of when it was built, thus eliminating any special treatment of generation built after July 9, 1996.'' *Citing* NOPR at P 72.

[318] NASUCA at 10–11.

[319] *Id.* at 11, *citing FPC* v. *Texaco, Inc.,* 417 U.S. 380 (1974) (stating that the prevailing price in the marketplace cannot be the final measure of just and reasonable rates) (*Texaco*). *See also* NASUCA reply comments at 7–8 (asserting that for any grandfathered sellers the market is the final determinant of price, an impermissible result under *Texaco*.)

commenter has demonstrated that harm would result from having to submit a horizontal market power analysis, and no commenter has claimed that it would lose its financing or that its financing would be adversely affected as a result of the elimination of the exemption in § 35.27(a). Moreover, as the Commission stated in Order No. 888, intervenors could present evidence that a seller seeking market-based rates for sales from new generation possesses market power, and sellers were aware that they may have to submit a horizontal market power analysis even if their generation fell within the exemption.[320] Therefore, we will require that all sellers seeking market-based rate authority for the first time on or after the effective date of the Final Rule in this proceeding must provide a horizontal market power analysis that includes all generation that the seller owns or controls.

330. All existing sellers that fall in Category 2 must provide a horizontal market power analysis that includes all generation that each seller owns or controls when it files its regularly scheduled updated market power analysis. To the extent a Category 1 seller acquires enough generation to be reclassified as a Category 2 seller, that seller will be required to submit a change in status report and provide a horizontal market power analysis.

331. Further, with regard to *PJM,* in establishing whether units constructed after July 9, 1996 should be exempt from PJM's existing market power mitigation rules, we initially approved the post-1996 exemption based on the concern that the price cap regulation or the mitigation rules in PJM might deter market entry and would create certain equity issues. However, we reconsidered our position and found that the exemption was unduly discriminatory by creating two classes of reliability must run generators: one that is price or offer capped and another that is not. Equally important, other RTOs/ISOs applied local market mitigation rules to all generation within their respective areas regardless of when the generator was built, and we determined that comparable authority for PJM would allow it to address local market power issues.[321] We concluded that units built on or after July 9, 1996 had the same ability to exercise market power as counterparts that were built prior to July 9, 1996. Accordingly, the Commission terminated the blanket exemption, but in the case of units that were built with the expectation that they would not be subject to mitigation, the Commission allowed the exemption to be grandfathered.[322]

332. Our reasons for grandfathering units in PJM are dissimilar enough that our holding in the *PJM* orders should not affect our decision here. The factors that led to the establishment and later the termination of the exemption from mitigation in PJM are unrelated to the reasons for instituting and, now, eliminating the express exemption in § 35.27(a). In *PJM* and *PJM II,* the Commission considered whether local market power mitigation might deter new entry and whether new units were built with the expectation that they would not be subject to mitigation. The Commission grandfathered units that could reasonably have relied on the exemption after it went into effect in their zone.[323] In contrast, in this proceeding the Commission desires a more rigorous market-based rate program and is concerned that over time generation will be retired leaving less and less generation subject to our horizontal analysis or sellers relying on the § 35.27 exemption will otherwise grow to a degree that they have market power in the relevant market in which they are located. The Commission's primary statutory obligation under FPA sections 205 and 206 is to ensure that rates are just and reasonable, and we believe the elimination of the exemption will better provide us with the ability to screen all market participants' ability to exercise horizontal market power regardless of whether their generation units were constructed before or after July 9, 1996. Therefore, we will not allow any grandfathering as part of this proceeding.

333. NASUCA's concerns regarding entities that originally enjoyed the § 35.27 exemption are addressed by our decision, discussed below in the Implementation Process section of this Final Rule, to require a seller that believes it qualifies as Category 1 to make a filing with the Commission at the time that its updated market power analysis for the seller's region would otherwise be due (based on the regional schedule set forth in Appendix D). That filing should explain why the seller meets the Category 1 criteria and should include a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area. Thus, a seller that previously qualified for the § 35.27 exemption and that believes it qualifies as a Category 1 seller would be required to provide support for its claim to Category 1 status. This filing will give the Commission and interested parties an opportunity to review and, if appropriate, challenge a seller's claim that it qualifies as a Category 1 seller. To the extent that an intervenor has concerns about a seller's potential to exercise market power, the Commission will entertain them at that time.[324] In addition, a seller that previously qualified for the § 35.27 exemption and that believes it qualifies as a Category 2 seller will be required to file an updated market power analysis based on the regional schedule set forth in Appendix D.

334. While it is true that a portion of these sellers will continue to sell at market-based rates for a time until their updated market power analyses (in the case of Category 2 sellers) or their filings addressing qualification as Category 1 sellers are due, no commenter has submitted compelling evidence that Category 1 sellers have unmitigated market power. We will rely on our change in status requirements that require, among other things, all sellers that obtain or acquire a net increase of 100 MW in owned or controlled generation to make a filing with the Commission and to provide the effect, if any, such an increase in generation has on the indicative screens. Additionally, all sellers must file EQRs of transactions no later than 30 days after the end of each reporting quarter. Furthermore, the Commission retains the ability to require an updated market power analysis from any seller at any time. With these procedures in place, we believe NASUCA's concerns are addressed.

c. Creation of a Safe Harbor

Comments

335. NRG urges the Commission to create a ''safe harbor'' such that ''if the generation owner controls less than 20 percent of the capacity in an organized market, the Commission should irrebuttably presume that the new entry will not contribute to market power and thus no demonstration is required to obtain market-based rate authority for the new capacity.'' [325] NRG states that

[320] *See* Order No. 888–A, FERC Stats.& Regs. Regulations Preambles July 1996–December 2000 ¶ 31,048 at 30,188 (''[T]he policy eliminates the [generation dominance] showing only as a matter of routine in each filing.'')

[321] *PJM, 110 FERC ¶ 61,053* at P 59.

[322] *PJM II, 112 FERC ¶ 61,031* at P 38.

[323] Nevertheless, the Commission stated that the units would still be subject to mitigation if PJM or its market monitor concluded that they exercised significant market power. *Id.* at P 60.

[324] Moreover, if specific concerns regarding market power exist, interested persons may file a complaint pursuant to FPA section 206.

[325] NRG at 5 & n.8, suggesting that the use of a 20 percent market share in the safe harbor proposal replicates one of the two screens that the

only where an owner controls more than 20 percent of capacity in a relevant market should the presumption be rebuttable and subject to challenge by intervening parties. It is NRG's contention that the creation of such a ''safe harbor'' retains most of the benefits of the Commission's current policy under § 35.27(a), while preserving its flexibility to investigate where a seller adding generating capacity already has a large market share. NRG believes that this codifies the general approach the Commission took in Order No. 888 [326] and responds to the Commission's evolving concerns in this area, while at the same time facilitating new entry in the organized markets where sufficient safeguards exist.[327] NRG contends that new generation, timely developed and brought online, is imperative; thus, a ''safe harbor'' for new generation is necessary.

336. Ameren agrees that there is a need for the Commission to address the § 35.27 exemption before it encompasses all generating capacity; however, Ameren submits that the Commission should allow an exemption for new generation under certain circumstances. Ameren argues that ''the Commission should amend its regulations to provide that new generation that represents less than 20 percent of the uncommitted capacity at peak in the relevant geographic market be exempt from the requirement of a horizontal market power analysis, so long as the owner of, or entity that controls, such capacity and its affiliates own no other generation or transmission facilities (other than interconnection facilities) in the relevant market.'' [328] Ameren submits that the Commission should allow the seller to file a letter which identifies: (1) The transmission system it is interconnected to; (2) the amount of uncommitted capacity it controls; and (3) the Commission-approved market power study that it relied on to determine that its uncommitted capacity is less than twenty percent of the net uncommitted capacity in the relevant geographic market. Ameren contends that this abbreviated process would reduce a seller's cost of compliance and administrative burdens.[329]

Commission Determination

337. The Commission will not create a safe harbor.[330] For the reasons set forth in the April 14 Order and reiterated in the July 8 Order, there will be no safe harbor exemption from the generation market power screen based upon a seller's size.[331] While there is no safe harbor exemption from the screens based on the seller's size, any seller, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate that do not affect the underlying methodology utilized by these screens.

338. Further, while we eliminate the § 35.27 exemption in this Final Rule, we note that sellers that have enjoyed that exemption historically have been required to address the other parts of the market-based rate analysis, vertical market power, affiliate abuse, and other barriers to entry.[332] Therefore, the Commission believes that, on balance, any additional cost of compliance or administrative burden due to this change will not be substantial compared to a seller's investment and revenues.[333]

11. Nameplate Capacity

Commission Proposal

339. In the NOPR, the Commission proposed to allow sellers the option of using seasonal capacity instead of nameplate capacity, as is currently required. The Commission indicated that the seller must be consistent in its choice and thus must choose either seasonal or nameplate capacity and use it consistently throughout the analysis. The Commission stated that it believed the use of seasonal capacity ratings more accurately reflects the seasonal real power capability and is not inconsistent with industry standards and, therefore, it may be more convenient for sellers to acquire and compile the associated data. The Commission added that it did not think the use of such ratings will materially impact results. The Commission sought comment on this proposal, including comment as to whether this information is publicly available to all market participants.

Comments

340. Many commenters on this topic express strong support for the proposal to substitute seasonal capacity for nameplate capacity.[334] The reason most commonly cited is that seasonal capacity is a more accurate representation of actual output. Several commenters state that firms should be allowed to use net seasonal capacity,[335] which allows for station service requirements and energy consumed by environmental equipment. MidAmerican points out that station usage, including environmental equipment, can approach 10 percent of overall output in steam plants.[336] EEI states that coal plants, which make up 51 percent of generation in the United States, are required to comply with both Federal and State regulations that mandate emission reductions. The plants are equipped with scrubbers and other emissions reduction technology that require a portion of the power produced by the plant in order to operate, thereby reducing the output available to serve customers. For companies with a large percentage of their generation coming from coal, the reduced output from such equipment could be significant.[337] PG&E favors using seasonal capacity if it could be filed confidentially, because it maintains that it is commercially sensitive information.[338]

341. PG&E requests clarification that if sellers are allowed to submit seasonal capacity, they are allowed to de-rate

Commission proposes in the NOPR to use as a general screen for market power in all markets reviewed for market-based rate authority. NRG argues that a 20 percent market share screen is well-established and appropriate for use in reviewing the market power implications associated with the addition of new generation. The use of a lightened, single screen approach to review the market power implications of new generation is appropriate, argues NRG, in that new generation expands the supply available in a market. According to NRG, for organized markets administered by RTOs that have in place Commission-approved market monitoring and mitigation authority, subjecting new generation only to a 20 percent market share screen is appropriate in light of the existing controls over the exercise of market power.

[326] *Id.* at n.9, citing Order No. 888, FERC Stats. & Regs., Regulations Preambles, January 1991—June 1996 ¶ 31,036 at 31,657.

[327] *Id.* at n.10. Under NRG's proposal, the Commission would also need to apply the safe harbor analysis to the notice of change of status for the suppliers' existing generation, when the notice of change is triggered by the addition of new generation capacity. Failure to do so would mean the lightened review appropriate for new generation would not, in effect, produce the intended lessening of regulatory burden.

[328] Ameren at 7–8.

[329] *Id.*

[330] We note that although Category 1 sellers are not required to provide a regularly scheduled updated market analysis, such an approach does not establish a safe harbor because all sellers will be required to perform the indicative screens as part of their initial applications, make change in status filings and file EQRs.

[331] *See* April 14 Order, 107 FERC ¶ 61,018 at P 69, 117; July 8 Order, 108 FERC 61,026 at P 107 (the Commission explained that small sellers are able to use simplifying assumptions).

[332] As described in this Final Rule, we consolidate the transmission market power and other barriers to entry analyses into one vertical market power analysis. In addition, we discontinue considering affiliate abuse as a separate part of the analysis and instead codify affiliate restrictions in our regulations.

[333] NOPR at P 71.

[334] Duke at 22; First Energy at 10; Southern at 26; SoCal Edison at 8.

[335] EEI at 18; PNM/Tucson at 10; Allegheny at 7–8; Pinnacle West at 5–6; PPL at 17.

[336] MidAmerican at 8.

[337] EEI at 18.

[338] PG&E at 10–11.

hydroelectric capacity resources based on historical output for the past five years, as specified in the April 14 Order.[339] Powerex supports seasonal ratings as more accurate, because hydroelectric systems are often able to generate in excess of nameplate ratings and these ''peak capability'' ratings are typically reflected in seasonal determinations, and seasonal ratings better reflect operating conditions that can impact the capacity ratings of renewable resources.[340]

342. APPA/TAPS support the adoption of seasonal capacity ratings if they are consistently used, and request that the Commission clarify that the seasonal capacity ratings be used for all plants in a geographic region ''so that the consistency benefits of the regional reviews are not diminished.'' [341]

Commission Determination

343. We will adopt the NOPR proposal that allows sellers to use seasonal capacity. We clarify that each seller must be consistent in its choice and thus must choose either seasonal or nameplate capacity and use it consistently throughout the analysis. In addition, a seller using seasonal capacity must identify in its submittal from what source the data was obtained.[342] We also note and adopt the Energy Information Administration (EIA) definition of seasonal capacity as it is reported on Form EIA–860, Schedule 3, Part B, Line 2, which provides that seasonal capacity is the ''net summer or winter capacity.'' [343] EIA instructions elaborate that ''net capacity should reflect a reduction in capacity due to electricity use for station service or auxiliaries,'' [344] which includes scrubbers and other environmental devices.

344. With regard to energy-limited resources, such as hydroelectric and wind capacity, in lieu of using nameplate or seasonal capacity in their submissions, we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor including a sensitivity test using the lowest capacity factor in the previous five years, and in recognition of Powerex's concern that hydroelectric systems can generate in excess of nameplate ratings and these ''peak capability'' ratings, the highest capacity factor in the previous five years. Our approach in this regard will more accurately capture hydroelectric or wind availability.[345]

345. We will not adopt APPA/TAPS' suggestion that we require use of either nameplate capacity or seasonal capacity throughout a region. While we appreciate APPA/TAPS' concern for data consistency for analysis purposes, we note that although we adopt a regional approach for the filing of updated market power analyses, the horizontal market power analysis itself continues to focus on the seller seeking to obtain or retain market-based rate authority. We find that consistency of data is critical within each individual analysis as results could vary depending on the assumptions taken. However, because we are not necessarily analyzing the entire region within a single study, we will not mandate the use of either nameplate capacity or seasonal capacity on a regional basis, but instead will allow sellers to choose either nameplate or seasonal capacity, and require them to identify the choice and use it consistently throughout the analysis.[346]

12. Transmission Imports

346. In the NOPR, the Commission proposed to continue to measure limits on the amount of capacity that can be imported into a relevant market based on the results of a simultaneous transmission import capability study. A seller that owns, operates or controls transmission is required to conduct simultaneous transmission import capability studies for its home control area and each of its directly-interconnected first-tier control areas consistent with the requirements set forth in the April 14 Order, as clarified in Pinnacle West Capital Corp.[347] These studies are used in the pivotal supplier screen, market share screen, and DPT to approximate the transmission import capability. When centering the generation market power analysis on the transmission providing utility's first-tier control area (*i.e.*, markets), the transmission-providing seller should use the methodologies consistent with its implementation of its Commission-approved OATT, thereby making a reasonable approximation of simultaneous import capability that would have been available to suppliers in surrounding first-tier markets during each seasonal peak. The transfer capability should also include any other limits (such as stability, voltage, Capacity Benefit Margin, or Transmission Reliability Margin) as defined in the tariff and that existed during each seasonal peak. The ''contingency'' model should use the same assumptions used historically by the transmission provider in approximating its control area import capability.

347. The Commission also proposed to reaffirm the exclusion of control areas that are second-tier to the control area being studied. In addition, it proposed that a seller's *pro rata* share of simultaneous transmission import capability should be allocated between the seller and its competitors based on uncommitted capacity. The Commission sought comment on this proposal.

a. Use of Historical Conditions and OASIS Practices

Comments

348. Montana Counsel states that transmission capability used in the tests should not be greater than the capability measures that are shown on the OASIS or that are used to measure ATC into markets unless there is a demonstrated change in available transmission capability.[348] In particular, Montana Counsel states that the Commission's requirement that sellers follow historical OASIS practice during each historical seasonal peak is essential; otherwise, companies could submit screens using transmission availability numbers that differ substantially from those which sellers and transmission

[339] April 14 Order, 108 FERC ¶ 61,018 at P 126. The July 8 Order allowed this method to be used for wind resources as well. July 8 Order, 108 FERC ¶ 61,026 at P 129.

[340] Powerex at 20.

[341] APPA/TAPS at 35.

[342] In the July 8 Order, the Commission stated that ''[w]ith respect to data that is only available from commercial sources, we clarify that commercial sources may be used to the extent the data is made available to intervenors and other interested parties. Applicants utilizing commercial information to perform the screens should include it in their filing.'' July 8 Order, 108 FERC ¶ 61,026 at P 121.

[343] EIA–860 Instructions are available at *http://www.eia.doe.gov/cneaf/electricity/forms/eia860/eia860.pdf*.

[344] Tip Sheet for Reporting on Form EIA–860, ''Annual Electric Generator Report'' at item ''III. Schedule 3B, Line 2 and Schedule 3D, Line 2: Net Capacity'' available at *http://www.eia.doe.gov/cneaf/electricity/forms/eia860/tipsheet.doc*.

[345] In the April 14 Order, we explained that commenters expressed concerns regarding the appropriate measure of the capacity of hydroelectric units given that hydroelectric facilities are energy-limited units. Our experience with Western markets shows that market outcomes can be significantly different during low water years. We agree with the comments raised by Western market participants and conclude that properly accounting for water availability will provide a better picture of competitive conditions in the West. Moreover, while not as critical in other parts of the country as in the West, the same principle regarding water availability applies to all electricity markets, and we will permit all sellers to de-rate hydroelectric capacity in the analysis.

[346] When submitting a change in status filing regarding horizontal market power, sellers should use the same assumptions they used (*e.g.*, use of nameplate or seasonal ratings) in their most recent market power analysis.

[347] 110 FERC ¶ 61,127 (2005).

[348] Montana Counsel at 4.

providers use in day-to-day activities in providing transmission market access.[349] In Montana Counsel's view, one cannot rely on capacity being able to reach a market based upon hypothetical transmission availability, as the Commission appropriately recognizes.

349. In response to Montana Counsel's assertion to use OASIS postings, PPL Companies maintain that the Commission should continue to use simultaneous import limit studies. OASIS postings do not adjust for transmission rights controlled by unaffiliated resources that may be used to compete against the seller in wholesale markets. PPL Companies state: ''The Commission should reject this proposal and continue to rely on [SILs]. The Commission properly has found that using actual OASIS postings understates import capability because OASIS postings do not take into account the capacity that may be imported as a result of existing reservations.''[350]

350. EEI and Southern request clarification of a perceived conflict in Appendix E, which instructs sellers to use Commission criteria for calculating simultaneous import capability and also to strictly follow their OASIS practices.[351] They recommend that the Commission clarify that if historical practices are different from Appendix E, historical practices should be used to calculate simultaneous transmission import capability and to allocate this transmission capability.

351. Duke asserts that scaling methods for calculating simultaneous transmission import capability should not be solely limited to historical practices used by the seller to post ATC on OASIS. Duke proposes a collaborative method involving the seller and transmission customers. Duke states: ''the Commission should allow applicants flexibility to use the appropriate methodology for SIL determinations including collaborative, regional efforts—so that screen results for control area markets can be accurate. For example, the Commission should not be overly prescriptive as to the scaling methodology to be used in such a collaborative effort, as long as the methodology is clearly defined and supported by the applicants.''[352] PPL Companies support the collaborative effort proposed by Duke, stating that sellers should have ''the option of proposing alternative [SILs] for first-tier markets, but would have to justify and document the proposed deviations.''[353]

352. Southern states that the SIL study requires ''blind'' scaling (scaling that does not consider economic dispatch) because only generation that is ''on-line'' is used. Southern states that to the extent a transmission provider does not customarily employ blind scaling, its use would not be consistent with historical practice. It asserts that a problem with blind scaling is that it does not necessarily reflect reality and therefore has the potential to understate, perhaps significantly, the simultaneous import limit.[354] EEI seeks clarification that the Commission is not requiring blind scaling in a manner that requires proportionate increases and decreases to generation resources. EEI requests clarification that scaling is allowed to include expert judgment reflecting how generation resources would likely be scaled up or down in a real-time operating environment. EEI contends that expert judgment in some cases may determine simultaneous import capability by scaling load rather than generation resources. EEI requests that the Commission defer to expert judgment in scaling and not be overly prescriptive as to whether generation or load is scaled to determine simultaneous import capability.[355]

353. PPL Companies contend the simultaneous import capability should not be limited by load in a control area. Since generators within the control area may sell power within or outside the control area, the Commission should consider the market prices of surrounding regions. If the prices are 105 percent or less, compared to control area prices, then the Commission should assume the resident control area resources will remain within the control area and not result in economic withholding within the seller's area.[356]

Commission Determination

354. The Commission will continue to require sellers to submit the Appendix E analysis, *i.e.*, the SIL study, to calculate aggregated simultaneous transfer capability into the balancing authority area being studied.[357] The Commission reaffirms that the SIL study is ''intended to provide a reasonable simulation of historical conditions'' [358] and is not ''a theoretical maximum import capability or best import case scenario.'' [359] To determine the amount of transfer capability under the SIL study, ''historical operating conditions and practices of the applicable transmission provider (*e.g.*, modeling the system in a reliable and economic fashion as it would have been operated in real time) are reflected.'' [360] In addition, the ''analysis should not deviate from'' and ''must reasonably reflect'' its OASIS operating practices[361] and ''the techniques used must have been historically available to customers.'' [362] We also reaffirm that the power flow cases (which are used as inputs to the SIL study) should represent the transmission provider's tariff provisions and firm/network reservations held by seller/affiliate resources during the most recent seasonal peaks.[363]

355. The Commission will also continue to allow sensitivity studies, but the sensitivity studies must be filed in addition to, and not in lieu of, an SIL study. We clarify that sensitivity studies are intended to provide the seller with the ability to modify inputs to the SIL study such as generation dispatch, demand scaling, the addition of new transmission and generation facilities

[349] *Id.* at 14.

[350] PPL Companies reply comments at 9–11.

[351] EEI at 27–29; Southern at 32.

[352] Duke at 27–28.

[353] PPL Companies reply comments at 9–11

[354] Southern at 35 and 36.

[355] EEI at 24.

[356] PPL Companies at 8.

[357] Benefits of using a uniform transmission import model include: Transparency, consistency, clarity, and reasonable assurance that system conditions have been adequately captured.

[358] In this regard, actual flows during the study periods may be used as a proxy for the simultaneous transmission import limit.

[359] NOPR at P 77.

[360] *Id.*

[361] By OASIS practices, we mean sellers shall use the same OASIS methods and studies used historically by sellers (in determining simultaneous operational limits on all transmission lines and monitored facilities) to estimate import limits from aggregated first-tier control areas into the study area. In this sense, sellers are modeling first-tier balancing authority areas as if they are the transmission operator/security coordinator (monitoring reliability) operating an OASIS for the aggregated first-tier footprint. We recognize that sellers are not the balancing authority area operators of first-tier balancing authority areas and in some instances, sellers may not be familiar with all aspects of their first-tier balancing authority areas' transmission system limits. However, sellers should be familiar with major constraints, path limits, and delivery problems in these neighboring transmission systems. If a seller participates in regional planning studies and day-to-day coordination with neighboring first-tier balancing authority areas then this will provide a reasonable basis for including transmission system constraints of first-tier balancing authority areas in SIL study calculations. In using OASIS practices the SIL study shall capture real-life physical limitations of first-tier balancing authority areas that impede power flowing from remote first-tier resources into the seller's study.

[362] *Id.* at P 77, 78.

[363] Network reservations include any grandfathered transmission rights applicable to the seller or its affiliated companies.

(and the retirement of facilities), major outages, and demand response.[364]

356. The Commission agrees with Montana Counsel and clarifies for PPL Companies that a SIL study must reflect transmission capability no greater than the capability measures that were historically shown on the OASIS or that were historically used to measure transmission capability into markets unless there is a demonstrated change in transmission capability, and account for the actual practice of posting ATC to OASIS in order to capture a realistic approximation of first-tier generation access to the seller's market. Further, and in response to EEI and Southern's comments, the Commission clarifies that when actual OASIS practices conflict with the instructions of Appendix E, sellers should follow OASIS practices and must provide adequate support in the form of documentation of these processes.

357. We disagree with Duke's argument that a seller's (generation or load) scaling methods should not be limited to historical OASIS practices when conducting an SIL. Using historical practices provides an appropriate method to obtain a transparent and measurable analysis of a seller's actual balancing authority area transmission conditions and practices. Improper or theoretical scaling methods which do not represent a seller's actual transmission practices may have the effect of allowing more competing generation into the balancing authority area than could actually be accommodated. This in turn has the effect of reducing a seller's generation market share and perhaps causing the seller to inappropriately pass the market share screen (a false negative).[365] In addition, relying on historical OASIS practices gives a seller the data needed to support its conclusions.

358. With regard to Duke and PPL's request that the Commission allow sellers to submit a flexible SIL study based on regional collaboration, the Commission finds that such an approach does not satisfy our concerns and may result in an unrealistic representation of the market.

359. Southern states that to the extent a transmission provider does not customarily employ blind scaling, its use would not be consistent with historical practice.

We agree and, as noted herein, the horizontal analysis and the SIL study are designed to study historical and realistic conditions during peak seasons. Accordingly, in this circumstance, sellers should follow their OASIS practices and must provide adequate support in the form of documentation of these processes.

360. With regard to EEI's argument that the Commission should consider allowing expert judgment in predicting real-time scaling techniques that will likely be used in real-time market environments, the Commission requires the use of a study that captures historical transmission operating practices. The SIL study is not a prediction of import possibilities; rather, it is a simulation of historical conditions. We assume that such historical conditions are the result of ''expert judgment'' used when determining generation dispatch and/or scaling techniques to make transmission capacity available during actual system conditions. Accordingly, this expert judgment is captured when conducting an SIL study that is based on historical operating practices.

361. In response to PPL's comments that the SIL should not be limited by load in a balancing authority area, the Commission reiterates that the SIL study is a benchmark of historical conditions, including peak load. It is a study to determine how much competitive supply from remote resources can serve load in the study area. Increasing the load in the study area beyond historical peak levels makes the study less realistic and can bias the study.[366] The Commission does, however, consider sensitivity studies on a case-by-case basis, when submitted in addition to the SIL study and supported by record evidence. For example, in Puget Sound Energy, Inc.'s (Puget) updated market power analysis filing, Puget demonstrated that the simultaneous transmission import limit was greater than the peak load in its balancing authority area, and the Commission allowed Puget to use a simultaneous transmission import limit based on its peak load.[367]

362. PPL also contends the simultaneous import capability should not be limited by load in a balancing authority area since generators within the balancing authority area may sell power within or outside the balancing authority area. Accordingly, PPL believes that the Commission should consider the market prices of surrounding regions. The Commission disagrees. We base the SIL on historical conditions that actually existed during the study periods. In this regard, PPL has provided no compelling reason for the Commission to abandon historical evidence in favor of a theoretical estimation of what could have occurred. We find that PPL's approach would make the studies more subjective and thus less accurate and more prone to dispute and controversy.

b. Use of Total Transfer Capability (TTC)

Comments

363. Southern asserts that the Commission's assumption that all TTC values posted on OASIS platforms are non-simultaneous is not correct. Southern states that although many TTC values may be calculated on a point-to-point non-simultaneous basis, some TTC values are simultaneous, thus accounting for ''loop flow'' created by other paths. Southern contends that those transmission providers that post simultaneous TTC values on OASIS should have the flexibility to add these TTC values to calculate simultaneous transmission import capability for the control area. Southern believes that conflicts can occur between the generic methods presented in the Appendix E interim market screen order and actual OASIS practices used by transmission providers to post TTC.

Commission Determination

364. Southern's suggestion that the Commission allow the use of simultaneous TTC values is consistent with the SIL study provided that these TTCs are the values that are used in operating the transmission system and posting availability on OASIS. The simultaneous TTCs[368] must represent more than interface constraints at the balancing authority area border and must reflect all transmission limitations within the study area and limitations within first-tier areas. The source (first-tier remote resources) can only deliver power to load in the seller's balancing authority area if adequate transmission is available out of its first-tier area, adequate transmission is available at the seller's balancing authority area

[364] We note that several sellers from the Western Interconnection have relied on Western Electricity Coordinating Council (WECC) path ratings for their SIL studies. The Commission has accepted these ratings when sellers have demonstrated that they are simultaneously feasible and take into account any interdependencies between paths.

[365] *See, e.g., Pinnacle West Capital Corp.,* 117 FERC ¶ 61,316 (2006).

[366] We note that there may be a circumstance where additional supplies could be imported above the market's study year peak load. If such a circumstance occurs, we will allow the seller to submit a sensitivity analysis in this regard and we will consider such an analysis on a case-by-case basis.

[367] *Puget Sound Energy, Inc.,* 111 FERC ¶ 61,020 at P 13 (2005).

[368] The simultaneous TTCs include seller's balancing authority area and aggregated first-tier areas.

interface, and transmission is internally available. Thus, the TTC must be appropriately adjusted for all applicable (as discussed below) firm transmission commitments held by affiliated companies that represent transfer capability not available to first-tier supply. Sellers submitting simultaneous TTC values must provide evidence that these values account for simultaneity, account for all internal transmission limitations, account for all external transmission limitations existing in first-tier areas, account for all transmission reliability margins, and are used in operating the transmission system and posting availability on OASIS.

c. Accounting for Transmission Reservations

Comments

365. Duke and EEI propose that short-term firm reservations should not be subtracted from simultaneous import limits because longer firm reservation requests can displace control of these transmission holdings.[369] EEI explains, ''it is inappropriate to net out transmission capacity that is not reserved to commit long-term generation resources to load. Short-term firm transmission reservations, some as short as one week in duration, provide flexibility to the market and will not necessarily persist for the duration, or even large portions, of the MBR authorization period. Therefore, they should not be used to reduce the estimate of simultaneous import capability.''[370]

366. Southern agrees, referring to the nature of short-term reservations as ''transient and unpredictable.'' [371] Southern states: ''In most cases, short-term purchases by the applicant essentially allow the market to provide generation within the applicant's control area instead of the applicant utilizing its 'owned' generation capacity. Alternatively, the associated import capability is released to the market. In either case, these short-term reservations should not be used to inflate artificially the applicant's market share in conjunction with a screen or DPT evaluation.'' [372]

367. APPA/TAPS state that the Commission should revisit the treatment of firm transmission reservations held by third parties. In the July 8 Rehearing Order (at P 49), the Commission stated that the SIL study assumed that ''all reservations historically controlled by non-affiliates would have been used to compete to inject energy into the transmission provider's control area market if market power or scarcity was driving market prices above other regional prices.'' However, if the holder of the reservation is using the transfer capability to serve its own load, it will not be available to third parties to respond to a price increase on the part of the transmission provider/sellers. APPA/TAPS state that presumably the capacity resources associated with the import will be reflected in the capacity total of the party that controls the resource's output. Excluding the transfer capability associated with the resource will not result in a double-deduction. Rather, failing to exclude the transfer capability will result in a double-counting of competing supply. Thus, APPA/TAPS assert that the Commission should revise the treatment of transfer capability held by third parties on a firm basis.[373]

Commission Determination

368. The Commission agrees with Duke, EEI and Southern that short-term firm reservations can be unpredictable, driven by real time system conditions, and do not necessarily indicate that the associated transmission capacity is not available for competing supplies (or to import seller's supplies during the study periods). Accordingly, we conclude that, in calculating simultaneous transmission import limits, short-term firm reservations of 28 days or less in effect during the study periods need not be accounted for.[374] While we find that firm transmission reservations less than or equal to 28 days in duration are usually unpredictable, we believe that firm transmission reservations of a longer duration are not related to the unpredictable nature of real time events and are based upon planned and predictable events. Therefore, the Commission will require sellers to account for firm and network transmission reservations having a duration of longer than 28 days.[375]

369. With regard to APPA/TAPSs' concern, we clarify that the seller's firm, network, and grandfathered transmission reservations longer than 28 days, including reservations for designated resources to serve retail load, shall be fully accounted for in the simultaneous import limit study. We further clarify that reservations held by third parties to import power into the seller's home area should be accounted for by allocating transmission import capability to those parties, and then allocating the remaining SIL pro rata.

d. Allocation of Transmission Imports Based on Pro Rata Shares of Seller's Uncommitted Generation Capacity

Comments

370. Duke and EEI support the Commission proposal to allocate imports on a pro rata basis into a study area based on uncommitted capacity in surrounding areas.[376]

371. However, Powerex expresses concern that pro rata allocation of uncommitted capacity is not a realistic representation of the physical capability of the system, since *pro rata* allocation assumes that the system can import up to the simultaneous import limit over any combination of transmission paths. Powerex argues that, in reality, some paths become constrained before others, so the allocation of import capability should take account of the physical limitations of the transmission system. Powerex asks that the Commission allow sellers to use allocation methods that are consistent with physical system limitations, where sellers provide documentation showing that the allocation methods used in the screens are realistic or conservative.[377]

372. Morgan Stanley asks the Commission to clarify its proposal of allocating transmission imports *pro rata* between the seller and its competitors based on uncommitted capacity. Morgan Stanley wonders if the Commission made a typographical error and intended to propose an allocation based on committed capacity. Morgan Stanley believes only the transmission provider (seller) would have uncommitted capacity.[378]

Commission Determination

373. The Commission agrees with Duke and EEI that the current practice of allocating simultaneous import

[369] Duke at 26–29.

[370] EEI at 25–26.

[371] Southern at 36–37.

[372] *Id.* at 37.

[373] APPA/TAPS at 53.

[374] We understand that short-term firm reservations are often used for unpredictable events and real-time system conditions. We note that most unpredictable conditions that sellers hold short-term firm reservations for, including generator forced outages and weather events, are less than one month in duration. Accordingly, we will allow applicants to not account for short-term firm reservations of one month or less, and since the shortest month is 28 days long, we are setting this limit at 28 days. Any firm reservation longer than 28 days in duration must continue to be accounted for in the SIL study.

[375] The simultaneous import limit study must account for short-term firm transmission rights including point-to-point on-peak/off-peak transmission reservations (firm or network transmission commitments) which have been stacked, or successively arranged, into an aggregated point-to-point transmission reservation longer than 28 days.

[376] Duke at 26–29, EEI at 25–26.

[377] Powerex at 24–25.

[378] Morgan Stanley at 15.

capability *pro rata* to sellers based on uncommitted capacity should be continued.[379] However, some clarification may be helpful.

374. Powerex raises concern over the *pro rata* allocation of uncommitted generation capacity and asserts that this is not a realistic representation of the physical capability of the system since *pro rata* allocation assumes that the system can import up to the simultaneous import limit over any combination of transmission paths. In this regard, we note that *pro rata* allocation of transmission capacity based on first-tier uncommitted generation capacity is an approximation and is consistent with the manner in which we conduct the SIL study. In particular, when determining the simultaneous import limit, first-tier balancing authority areas are combined into a single area. The import capability of the study area is the simultaneous transfer limit from the aggregated first-tier market area into the study area.[380] We then allocate imports based on transmission capacity (limited by the physical capabilities of the transmission system as determined by the SIL study) *pro rata* based on sellers' first-tier uncommitted generation capacity.[381] We recognize that such an approximation may not fit all cases. Accordingly, with regard to allocating transmission imports, sellers can submit additional sensitivity studies based on factors suggested by Powerex, and intervenors may rebut the allocations of import capability made by seller. The Commission will consider such arguments on a case-by-case basis.

375. Morgan Stanley asks if the Commission made a typographical error and intended to propose an allocation based on committed capacity rather than uncommitted capacity. The Commission clarifies that *pro rata* allocation is used to assign shares of simultaneous transmission import capability to uncommitted generation capacity in the aggregated first-tier balancing authority areas to determine how much uncommitted generation capacity can enter the study area. Morgan Stanley appears to confuse our use of the term uncommitted capacity, apparently believing we are referring to uncommitted transmission capacity. That is not the case as we are referring to uncommitted generation capacity. The reason the use of uncommitted generation capacity is appropriate is because our screens analyze seller's relative uncommitted generation capacity rather than installed generation capacity or, as suggested by Morgan Stanley, committed generation capacity. In particular, the SIL study determines the amount of simultaneous transmission capacity available to be imported by competing supplies from remote resources in first-tier markets. The supplies that are available to be imported and thus compete are necessarily ''uncommitted.'' Further, it is our experience that uncommitted generation capacity can be held by any number of market participants based on market conditions at a given time. In other words, we do not agree with an assumption that the transmission provider is likely to be the only market participant with uncommitted power supplies.

e. Miscellaneous Comments

Comments

376. PG&E states that RTOs/ISOs having knowledge and control over the entire control area are best suited to perform SIL studies. PG&E requests that the Commission allow an exemption where, in the absence of an accepted SIL study by an RTO/ISO, the seller may substitute historical import levels in place of the SIL study. In addition, PG&E requests that the Commission confirm that sellers that pass screens for each relevant geographic market without considering imports need not provide a simultaneous import analysis.[382]

377. Powerex has concerns about how feasible it is for marketers to obtain non-public data from their transmission provider that is needed to conduct a screen (*e.g.*, a SIL study) on their own. Powerex notes that Bonneville Power Administration (BPA) and Northwest Power Pool (NWPP) do not, as a practice, conduct and post simultaneous transmission import capability studies. Therefore, Powerex asserts that the Commission should maintain the current flexibility of allowing marketers to submit credible proxy study calculations based on publicly available information.[383]

Commission Determination

378. The Commission will continue to require the SIL study for the indicative screens and DPTs in order to assure that restrictions regarding importing first-tier supply are captured for seasonal peak conditions. Benefits of using a uniform transmission import model include: Transparency, consistency, clarity, and reasonable assurance that system conditions have been adequately captured. As also stated above, the Commission provides sellers flexibility to provide sensitivity analyses by modifying inputs to the SIL study.

379. In regard to PG&E's belief that RTOs/ISOs are best equipped to conduct SIL calculations, the Commission will continue to require transmission-providing sellers to perform the SIL studies as necessary. To the extent that an RTO/ISO conducts transmission studies and makes that information available, a seller may rely on the information obtained from its RTO/ISO to conduct its SIL study. Further, the Commission clarifies that to the extent the transmission-owning seller can demonstrate it passes the screens for each relevant geographic market without considering imports, it need not submit a SIL study.[384]

380. Powerex requests that it be able to submit proxies in place of a SIL study. The Commission notes that transmission-providing sellers are required to be the first to file SIL studies, which makes the required data available to non-transmission owning sellers for use in performing their generation market power analyses.[385] However, as the Commission stated in the April 14 Order,

> an applicant may provide a streamlined application to show that it passes our screens. Thus, with respect to simultaneous import capability, if an applicant can show that it passes our screens for each relevant geographic market without considering imports, no such simultaneous import analysis needs to be provided. Further, we recognize that certain applicants will not have the ability to perform a simultaneous import capability study. Accordingly, if an applicant demonstrates that it is unable to perform a simultaneous import study for the control area in which it is located, the applicant may propose to use a proxy amount for transmission limits. We will consider such proposals on a case-by-case basis.[386]

381. In this regard, we note that we have accepted proxy amounts for

[379] Allocation of the simultaneous transmission import capability, into the seller's market, to affiliated and unaffiliated uncommitted first-tier generation is done in the indicative screen, after conducting the SIL study, in order to estimate uncommitted capacity market shares from first-tier balancing authority areas.

[380] April 14 Order, 107 FERC ¶61,018 at Appendix E.

[381] The SIL study also accounts for transmission reservations when determining the amount of imports available to reach the study area as discussed herein and in the April 14 and July 8 Orders.

[382] PG&E at 11–12. PG&E also requests that the Commission clarify how to perform the simultaneous import limitation to avoid the need for repetitive studies. However, PG&E did not specify what clarification was sought in this regard.

[383] Powerex at 5–25.

[384] April 14 Order, 107 FERC ¶ 61,018 at P 85.

[385] July 8 Order, 108 FERC ¶ 61,026 at 46.

[386] April 14 Order, 107 FERC ¶ 61,018 at P 85.

transmission limits and will continue to consider such requests on a case-by-case basis.[387]

f. Required SIL Study for DPT Analysis

Comments

382. EEI and Southern propose that the Commission not mandate SIL studies as the only method for calculating import limits for DPT analysis. EEI states that while such a study may be an appropriate tool for indicative screens, the DPT is a more comprehensive study and the Commission should allow for more precise, non-standardized approaches for calculating simultaneous import capability for use in the DPT.[388] Southern states that the apparent purpose of Appendix E is to provide a somewhat standardized approach to assessing simultaneous import capability that goes hand-in-hand with the simplified tools used to develop a preliminary assessment of generation market power. It argues that where a seller presents a more thorough generation analysis pursuant to a DPT, it should be permitted to offer a more thorough analysis of transmission import capability.[389]

383. NRECA responds that the Commission should not allow sellers to substitute alternative measures of simultaneous import capability in the DPT. NRECA states that while a seller should be allowed to conduct a SIL study that is more refined than the one required of all sellers, ''the applicant's alternative analysis should be submitted in addition to, and not in lieu of, the required analysis'' in the DPT.[390] It argues that otherwise, each seller will do the analysis a bit differently so that the analysis will favor passing the tests. According to NRECA, the worst-case scenario is that there will be no standardized approach, which would exacerbate the existing problems created by inadequate access to the data underlying the sellers' market power analysis and the lack of standard reporting and increase the burdens on intervenors and the Commission staff in evaluating applications for market-based rates and market power updates. NRECA states that one advantage of requiring all sellers to use a standard analysis, in addition to whatever other analysis they may choose to offer, is that it can more effectively bring to light the problems now hidden from view in the seller's historical practices, resulting in increased transparency.

Commission Determination

384. For the reasons stated herein regarding the need to as accurately as possible account for transmission limitations when considering power supplies that can be imported into the relevant market under study, the Commission adopts the requirement for use of the SIL study as a basis for transmission access for both the indicative screens and the DPT analysis.

385. The lack of flexibility in creating a simultaneous transmission import limit has been identified by several commenters. However, the Commission believes it has provided sellers sufficient flexibility to adequately represent their process for making transmission available to unaffiliated supply. The Commission shares NRECA's concerns that opening the process to alternative study methods without a specified standard may result in deviations from reasonable depictions of transmission limits historically applied to first-tier suppliers and will likely bias such studies to the benefit of the seller.

386. With regard to the DPT analysis, there are several primary reasons for the continued use of simultaneous transmission import limit studies: Uniformity of modeling affiliated and unaffiliated supply, consideration of simultaneity, consideration of seller and affiliate transmission commitments and reservations, consideration of all internal transmission limitations, consideration of all external transmission limitations existing in first-tier areas, consideration of the seller's (or the seller's transmission provider's) practices for posting ATC, and consideration of peak seasonal conditions. By requiring the SIL study in the DPT analysis, the Commission assures that all factors important in determining transmission access to the seller's market are taken into account.

13. Procedural Issues

Commission Proposal

387. In the NOPR, the Commission noted that Order No. 662 [391] addressed concerns that CEII claims in market-based rate filings are overbroad. In Order No. 662, the Commission stated that it is willing to consider on a case-by-case basis requests for extensions of time to prepare protests to market-based rate filings where an intervenor demonstrates that it needs additional time to obtain and analyze CEII. In Order No. 662, the Commission encouraged the parties in cases in which CEII is filed to promptly negotiate a protective order governing access to the CEII, or privately negotiate for the submitter to provide the data to interested parties pursuant to an appropriate non-disclosure agreement. The Commission sought comments in the NOPR on whether CEII designations remain a concern since issuance of Order No. 662.

388. The Commission also sought comments regarding whether the comment period (generally 21 days from the date of filing) provided for parties to file responses to the indicative screens and DPT analyses is sufficient. The Commission asked what would be an appropriate comment period if it were to establish a longer period for submitting comments on indicative screen and DPT analyses.

Comments

389. A number of commenters note that intervenors should be given adequate time to respond to CEII designations. APPA/TAPS suggest that the Commission provide a process to allow interested market participants to obtain CEII authorization in advance of a region's triennial updates. They submit that such authorization would apply to all sellers in the region where market-based rate authority is up for review and would necessitate that the requester file only one request.[392] Montana Counsel states that intervenors should also be given adequate time to respond to confidentiality claims with regard to non-CEII data.[393]

390. A number of commenters support extending the comment period for market-based rate filings. Ameren supports a 30-day comment period on the basis that 30 days has proven to be a sufficient comment period for section 203 filings.[394] Morgan Stanley recommends a 45-to 60-day comment period if the Commission adopts a regional approach for updated market power analyses.[395] NRECA states that under a regional filing process, a 21-day comment period is inadequate when several updated market power analysis filings are reviewed at once, and instead advocates a 90-day comment period from the notice of the filing or from the

[387] *See, e.g., Tampa Electric Co.,* 110 FERC ¶ 61,026 at P 32 (2005) (using the largest ATC into the control area at the time the study is conducted is a conservative assumption for import capability and an acceptable proxy for the SIL study).

[388] EEI at 24–25.

[389] Southern at 4, 37–38.

[390] NRECA reply comments at 24–25.

[391] *Critical Energy Infrastructure Information,* Order No. 662, 70 FR 37031 (June 28, 2005), FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,189 (June 21, 2005).

[392] APPA/TAPS at 35–36.

[393] Montana Counsel at 23–24.

[394] Ameren at 8.

[395] Morgan Stanley at 14.

date of a completed filing if additional data is requested by the Commission.[396]

Commission Determination

391. In this Final Rule, we adopt procedures under which intervenors in section 205 proceedings may obtain expedited access to CEII or other information for which privileged treatment is sought. A request for access to information for which CEII status or privilege treatment has been claimed generally takes a few weeks for the Commission to process under the standard process found in 18 CFR 388.112 and 388.113.[397] Such a delay in receiving such information may make it difficult for an intervenor to submit timely comments.

392. An expedited process does exist for section 203 filings. Section 33.9 of the Commission's regulations [398] states that a seller seeking to protect any part of its application from public disclosure must also submit a proposed protective order. Parties may sign the proposed protective order and obtain CEII or privileged materials in a more timely manner, without having to spend time negotiating the terms of a protective order or waiting for the Commission to process the request through its standard request process.

393. In order to ensure that intervenors have access in a timely manner to relevant information for which privileged treatment is claimed, we will adopt language similar to § 33.9 in this Final Rule, to be codified at 18 CFR 35.37(f). We intend that the proposed protective order will be self implementing and not require action by the Commission; once a party signs the proposed protective order and returns it to the party submitting protected material, the submitter is expected to provide the material promptly to the requester. We note that the Commission's Model Protective Order is available on the Commission's Internet site and may be used as a guide in preparing proposed protective orders.[399] To expedite processing, the regulation will require that the seller provide the CEII or privileged material to the requester within five days after the protective order is signed and submitted to the seller.

394. With respect to APPA/TAPS's suggestion to make CEII authorization region-wide to coincide with region-wide analysis, we do not believe such a step is necessary or advisable at this time. Our goal with CEII has always been to limit access to those with a legitimate need for the information. We do not expect that all market participants in a region will want to comment on all updated market power analyses within that region. Moreover, we anticipate that our regulatory change requiring submission of a proposed protective order will go a long way to resolving past difficulties in obtaining non-public information in a timely manner.

395. With regard to the comment period for parties to file responses to updated indicative screens, we believe, as we discuss below in the section on Implementation, that extending the comment period for regional updated market power analyses will allow intervenors a better opportunity to review and comment on those filings, especially considering the large number of filings that will be submitted at one time. Hence, we will establish a 60-day comment period for updated market power analyses that are filed in accordance with the schedule in Appendix D.

396. With regard to the comment period for initial applications and for DPT analyses ordered as part of a section 206 proceeding, the Commission will retain the current 21-day comment period. However, we remain willing to consider on a case-by-case basis requests for extensions of time beyond 21 days to submit comments on these filings.

B. Vertical Market Power

397. In the NOPR, the Commission proposed to replace the existing four-prong analysis (generation market power, transmission market power, other barriers to entry, affiliate abuse/reciprocal dealing) with an analysis that focuses on horizontal market power and vertical market power. Accordingly, it proposed that issues relating to whether the seller and its affiliates have transmission market power or whether they can erect other barriers to entry be addressed together as part of the vertical market power part of the analysis.

Comments

398. As a general matter, commenters expressed support for the proposed consolidation of the transmission market power and other barriers to entry prong into one vertical market power analysis.[400] According to EPSA, analyzing vertical market dominance in one single prong could be a positive step, provided that the elements of the prong are explicitly specified and effectively enforced.[401] No commenter opposed the Commission's proposal in this regard.

Commission Determination

399. In light of the reasons discussed in the NOPR and the comments received, the Commission will adopt the NOPR proposal to consolidate the transmission market power analysis and other barriers to entry analysis into one vertical market power analysis.

1. Transmission Market Power

Commission Proposal

400. In the NOPR, the Commission noted that it recognized that Order No. 888 did not eliminate all potential to engage in undue discrimination and preference in the provision of transmission service,[402] and that it had issued a Notice of Inquiry and a NOPR regarding whether reforms are necessary to the Order No. 888 *pro forma* OATT.[403] The Commission concluded that any concerns regarding the adequacy of the OATT should be addressed in that proceeding and not in the MBR Rulemaking proceeding. Therefore, in the NOPR the Commission proposed to continue to find that, where a seller or any of its affiliates owns, operates or controls transmission facilities, a Commission-approved OATT, as modified as a result of the OATT Reform Rulemaking, will adequately mitigate transmission market power.

401. In the NOPR, the Commission further stated that the finding that an

[396] NRECA at 29.

[397] This is due, in part, to the fact that the Commission's regulations require notice and an opportunity for the submitter to comment on the request. The Commission recently consolidated the notice and opportunity to comment provision in 18 CFR 388.112(d) with the notification prior to release found in 18 CFR 388.112(e). *See Critical Energy Infrastructure Information,* Order No. 683, FERC Stats. & Regs. ¶ 31,228 (2006).

[398] 18 CFR 33.9.

[399] *See http://www.ferc.gov/legal/admin-lit/model-protective-order.pdf.*

[400] *See* Duke at 30; Southern at 38–40; EPSA at 18–19.

[401] EPSA at 18–19.

[402] In Order No. 2000, the Commission found that ''opportunities for undue discrimination continue to exist that may not be remedied adequately by [the] functional unbundling [remedy of Order No. 888]* * *'' *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,105 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[403] See *Preventing Undue Discrimination and Preference in Transmission Service*, 70 FR 55796 (Sept. 23, 2005), FERC Stats. & Regs., ¶ 35,553 (2005); *Preventing Undue Discrimination and Preference in Transmission Service*, Notice of Proposed Rulemaking, 71 FR 32636 (Jun. 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *reh'g pending.*

OATT adequately mitigates transmission market power rests on the assumption that individual sellers comply with their OATTs. If they do not, violations of the OATT may be cause to revoke market-based rate authority or to subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[404] However, before the Commission will consider revoking an entity's market-based rate authority for a violation of the OATT, there must be a nexus between the OATT violation and the entity's market-based rate authority.

402. In addition, the Commission proposed that, if it determines, as a result of a significant OATT violation, that the market-based rate authority of a transmission provider will be revoked within a particular market, each affiliate of the transmission provider that possesses market-based rate authority will have it revoked in that same market on the effective date of revocation of the transmission provider's market-based rate authority.[405]

a. OATT Requirement

Comments

403. Several commenters state that merely having an OATT on file does not sufficiently mitigate vertical market power and that a utility's interpretation and implementation of its OATT can effectively eviscerate market power protections.[406] Some commenters do not believe that tariff changes alone will effectively mitigate vertical market power in the future and therefore request a post-implementation proceeding one year after the issuance of a final rule in the OATT Reform Rulemaking to explore the effectiveness of the updated OATT in assessing vertical market power.[407]

404. EPSA states that the outcome of the OATT Reform Rulemaking will determine the strength and efficacy of the vertical market power screen and stresses the interrelationship of that proceeding to this proposed rule; EPSA continues to advocate that the reform of Order No. 888 and the ability of the OATT to mitigate against market power effectively be evaluated on an ongoing basis.[408]

405. APPA/TAPS similarly state that, for purposes of the vertical market power analysis, it is too early to tell whether the OATT, as modified in the OATT Reform Rulemaking, will mitigate transmission market power.[409] TDU Systems argue that the proposals governing transmission planning and expansion in the OATT Reform Rulemaking are inadequate to mitigate the vertical market power of transmission-owning public utilities.[410]

406. The New York Commission states that the presence of an OATT may mitigate a seller's transmission market power, but only with respect to generator access to the transmission system. It submits that vertically integrated utilities may be able to exercise transmission market power in a manner that would not necessarily violate their OATTs, such as through outage scheduling (*e.g.*, delaying repair and maintenance of transmission lines in a load pocket in which an affiliated generator is located), transmission investment (*e.g.*, delaying or minimizing its investment in the bulk electric transmission system in a load pocket in which an affiliated generator is located), or voltage support (*e.g.*, inadequate support of voltage requirements and being slow to correct voltage support shortcomings).[411] EPSA agrees with the New York Commission that the Commission cannot assume that any transmission provider with a Commission-approved OATT on file has adequately mitigated transmission market power and that ''the Commission should require these utilities to demonstrate that they do not have the incentive or ability to engage in such behavior, before they are granted MBR status.'' [412]

407. On the other hand, several commenters support the Commission's proposal to maintain the long-standing presumption that a Commission-approved OATT will adequately mitigate transmission market power.[413] EEI states that the comprehensive approach that the Commission has taken to reform the OATT in the OATT Reform Rulemaking is the best approach to assess the adequacy of the OATT to mitigate transmission market power. EEI states that the Commission should continue to find that a Commission-approved OATT, as modified as a result of the OATT Reform Rulemaking, adequately mitigates transmission market power.[414]

Commission Determination

408. The Commission will adopt the NOPR proposal that, to the extent that a public utility with market-based rates, or any of its affiliates, owns, operates, or controls transmission facilities, the Commission will require that a Commission-approved OATT be on file before granting such seller market-based rate authorization. We recognize that the Commission has granted a number of entities waiver of the requirement to file an OATT where the filing entity satisfies the Commission's standards for the grant of such waivers.[415] The Commission will continue to grant waiver of the OATT requirement on a case-by-case basis, and will continue to allow sellers to rely on the grant of such waiver to satisfy the vertical market power part of the analysis. If a seller that previously received waiver of the OATT requirement seeks to continue to rely on that waiver to satisfy the vertical market power part of the analysis, it must make an affirmative statement in its updated market power analysis that it previously received such a waiver, that such waiver remains appropriate, and the basis for that claim. In addressing our vertical market power concerns, a seller, including its affiliates, that does not own, operate or control transmission facilities must make an affirmative statement that neither it, nor any of its affiliates, owns, operates or controls any transmission facilities.

409. In the NOPR, we stated that concerns regarding the adequacy of the OATT should be addressed in the OATT Reform Rulemaking. The Commission received over 6,000 pages of comments relating to potential reforms to the *pro forma* OATT in that proceeding, and on February 16, 2007 issued a Final Rule adopting numerous improvements to the *pro forma* OATT that will further limit opportunities for transmission providers to unduly discriminate against transmission customers. As a result, we do not address in this Final Rule specific reforms to the OATT. In addition, the Commission declined in Order No. 890 to establish a one-year review period for the reformed *pro forma* OATT. The Commission stated it will continue to actively monitor compliance with its orders and, as necessary, institute further proceedings

[404] NOPR at P 91 (citing *The Washington Water Power Co.*, 83 FERC ¶ 61,282 (1998)).

[405] NOPR at P 91.

[406] *See*, *e.g.*, Suez/Chevron at 6; Reliant at 8.

[407] Suez/Chevron at 6; EPSA at 20.

[408] EPSA reply comments at 2, 5.

[409] APPA/TAPS at 6.

[410] TDU Systems at 24.

[411] New York Commission at 2–4.

[412] EPSA reply comments at 5–6 (citing New York Commission at 2–4).

[413] Duke at 29–32; EEI at 44–45; Southern at 38–40; MidAmerican reply comments at 2.

[414] EEI reply comments at 31–35.

[415] *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232 at 61,941 (1996) (granting waiver of Order No. 888 for public utilities that can show that they own, operate, or control only limited and discrete transmission facilities (facilities that do not form an integrated transmission grid), until such time as the public utility receives a request for transmission service).

to meet its statutory obligation to remedy undue discrimination.[416]

410. In response to the concerns of the New York Commission and EPSA that vertically integrated utilities may exercise vertical market power without violating their OATTs through actions such as outage scheduling, investment decisions and inadequate voltage support, we note that the OATT does address such matters as the planning and expansion of facilities, the duty to provide firm and non-firm service and good utility practice. These provisions impose definite obligations on transmission providers. As additional examples, outage scheduling aimed at affecting market prices may constitute market manipulation, and inadequate voltage support may violate a reliability standard under FPA section 215. These provisions adequately address the concerns of the New York Commission and EPSA.

b. OATT Violations and MBR Revocation

Comments

411. A number of commenters agree with the Commission that market-based rate authority should not be revoked unless and until the Commission finds a direct nexus between the OATT violation and the entity's market-based rate authority.[417] EEI states that the Commission should not presume that an OATT violation is sufficient cause to revoke a transmission provider's market-based rate authority because there is no basis for such a presumption.[418] Instead, EEI argues that the Commission should carefully review all facts and circumstances before determining that an OATT violation was a willful exercise in undue discrimination intended to benefit a seller's sales at market-based rates.[419]

412. EPSA asserts that any violation of an entity's OATT in order to favor its own sales or its affiliates would create a nexus to the entity's market-based rate authority. If the Commission does not clarify this point, EPSA requests explanation regarding what exactly would constitute a nexus between an OATT violation and an entity's market-based rates.[420]

413. TDU Systems state that it is unclear what the nexus requirement entails. They propose that if the transmission provider or one of its affiliates has market-based rate authority, there should be a rebuttable presumption that a violation of the OATT has the requisite nexus to support revocation of the market-based rate authority of the transmission provider and its affiliates.[421] TDU Systems state that it should be up to a seller to rebut that presumption.

414. APPA/TAPS assert that the nexus standard adds an unnecessary and counter-productive test.[422] APPA/TAPS submit that if an OATT violation denies, delays, or diminishes the availability of transmission service or raises its costs, that alone should suffice for consideration of revocation of market-based rate authority. They argue that whether the violation had a nexus to the seller's market-based rate sales may be irrelevant. APPA/TAPS state that a nexus requirement could divert the Commission and injured parties through needless disputes about whether the alleged violator used the OATT violation to enable a specific sale under its market-based rate tariff authority, ignoring the larger picture painted by the transmission provider's anticompetitive conduct and exercise of transmission market power. Thus, instead of the ''nexus'' standard, APPA/TAPS states that the Commission should require that the OATT violation be ''material,'' *i.e.*, one that denies customers the just, reasonable and non-discriminatory and comparable transmission service that is essential to mitigation of transmission market power.[423]

415. Reliant suggests that the Commission should strengthen its vertical market power analysis by looking at the extent to which a transmission provider has denied transmission access to competing suppliers and should seek justification for such denials.[424] For those transmission providers seeking market-based rate authority, Reliant asserts that any suppliers unable to reach a customer as a result of an inappropriate denial should not be included as competing generation in the transmission provider's horizontal market power screens until the transmission provider remedies the problem.[425]

416. Duke urges the Commission to clarify that a seller's market-based rate authority should not be subject to limitation or revocation if it participates in an RTO that is the subject of an OATT violation. According to Duke, once the transmission owner transfers control over its facilities to an RTO, adherence to the OATT is in the control of the RTO, not the transmission owner.[426]

Commission Determination

417. We will adopt the NOPR proposal to revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority, and reiterate our statement in the NOPR that an OATT violation may subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[427] As stated in the NOPR, the finding that an OATT adequately mitigates transmission market power rests on the assumption that individual entities comply with the OATT and there may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement,[428] merit revocation or limitation of market-based rate authority. We find, however, that it is inappropriate to revoke a seller's market-based rate authority for an OATT violation unless there is a nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority. This will ensure that our actions are not arbitrary or capricious and that they are based on an adequate factual record. We will not, as TDU Systems suggest, adopt a rebuttable presumption that any OATT violation has the requisite nexus to support revocation of market-based rate authority. There is a wide range of types of OATT violations, including ones that may be inadvertent and ones that are neither intended to affect, nor in fact affect, the market-based rate sales of the transmission provider or its affiliates. We therefore believe adoption of a general rebuttable presumption of a nexus for any and all OATT violations is not justified.

418. Several commenters sought clarification regarding what would constitute a sufficient nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority. Determining what

[416] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 42.

[417] EEI reply comments at 31–35; MidAmerican reply comments at 2. *See also* Duke at 29 (OATT violation should be a material violation and related in some way to the seller exercising market power).

[418] EEI reply comments at 31–35.

[419] EEI reply comments at 34; PNM/Tucson at 10–12.

[420] EPSA at 23–24.

[421] TDU Systems at 21–23.

[422] APPA/TAPS at 81–82.

[423] *Id.* at 82.

[424] *See* Reliant at 8–9.

[425] *See id.*

[426] Duke at 29–32.

[427] NOPR at P 91 (citing *The Washington Water Power Company,* 83 FERC ¶ 61,282 (1998)).

[428] *Enforcement of Statutes, Orders, Rules and Regulations,* Policy Statement on Enforcement, 113 FERC ¶ 61,068 (2005) (Enforcement Policy Statement).

constitutes a sufficient factual nexus is best left to a case-by-case consideration. The wide range of positions among commenters on how to define a sufficient factual nexus itself suggests that this finding is best made after review of a specific factual situation. Some commenters assert that a finding of a ''material'' violation of the OATT would be sufficient. We disagree. While a seller's inconsequential OATT violation would not serve as a basis for revoking that entity's market-based rate authority, our view is that revocation is warranted only when an OATT violation has occurred and the violation had a nexus to the market-based rate authority of the violator or its affiliates.

419. The Commission emphasizes that we have discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances in which we do not find sufficient justification for revocation of that authority. For example, in appropriate circumstances, we may modify or add additional conditions to the violator's market-based rate authority or impose other requirements to help ensure that the violator does not commit future, similar misconduct. We also will consider whether to impose sanctions such as assessment of civil penalties for particularly serious OATT violations in addition to revocation of the violator's market-based rate authority.

420. We agree with Duke that a seller's market-based rate authority should not be subject to limitation or revocation if it participates in an RTO that is the subject of an OATT violation committed by the RTO. We note, however, that if the seller itself is involved in an OATT violation, the Commission will investigate the seller's actions where appropriate, and may revoke market-based rate authority even though the seller is in an RTO.

421. With regard to Reliant's suggestion that the Commission should examine the extent to which a transmission provider has denied transmission access to competing suppliers as part of its vertical market power analysis, we will allow intervenors on a case-by-case basis to file evidence if they believe they have been denied transmission access in violation of the OATT. Depending on specific facts, such denials could constitute an OATT violation and could warrant remedies such as a reduction of competing supplies for purposes of the horizontal analysis.

c. Revocation of Affiliates' MBR Authority

Comments

422. Some commenters oppose the proposal to revoke the market-based rate authority of all affiliates of a transmission provider within a particular market, regardless of whether they were involved in the transmission provider's violation of its OATT. These commenters argue that the proposal to revoke all affiliates' market-based rate authority ignores the principles of the Commission's code of conduct and standards of conduct, including provisions restricting the sharing of market information and requiring separation of functions.[429] They argue that, in light of the separation of a company's marketing function and transmission function under the standards of conduct, a company's market-based rates should not be revoked because of an OATT violation by an affiliated transmission owner unless there has also been a violation of the standards of conduct, and there is a nexus between the standards of conduct violation and the OATT non-compliance.[430] They assert that, unless there is a violation of the standards of conduct, merchants will have no involvement in the actions of transmission providers.[431]

423. Xcel submits that, before imposing a penalty that would effectively penalize the merchant function, the Commission should require a demonstration that a utility's transmission function violated the OATT so as to knowingly benefit the activities of its merchant function.[432] Xcel and Allegheny Energy state that the Commission should not penalize the merchant side of an entity when the OATT violation by the transmission provider causes no harm, was not the result of deliberate manipulative conduct, was not part of a pattern of misconduct, or did not involve senior management of the transmission provider.[433] Similarly, Indianapolis P&L advocates punishment of a marketing or generation-only affiliate only to the extent such affiliate colludes or conspires with such OATT mis-administration or if such an affiliate financially benefits from such an act.[434]

Commission Determination

424. In response to concerns raised by commenters, we do not adopt the proposal from the NOPR to revoke the market-based rate authority of each affiliate of a transmission provider that loses its market-based rate authority within a particular market as a result of the transmission provider's OATT violation. Rather, we will create a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation. We will allow an affiliate of a transmission provider to retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption with respect to that market area.

425. This issue generally will arise when a transmission provider merits revocation of its market-based rate authority as a result of an OATT violation. We have long held that the existence of an OATT is deemed to mitigate vertical market power by a transmission provider and its affiliates in a particular market. An OATT violation by a transmission provider that merits revocation of the transmission provider's market-based rate authority in a particular market will, at a minimum, raise the question whether the transmission provider's affiliates continue to qualify for market-based rates in that market under the standards that we have established.[435]

[429] *See* Ameren at 8–11; PNM/Tucson at 10–12; EEI reply comments at 33–35; Avista at 12–13; EEI at 54; Indianapolis P&L at 6–7.

[430] *See* PG&E at 3, 12–14; Xcel at 2 and 16.

[431] PG&E at 13.

[432] Xcel at 16–17. *See also* Avista at 12–13; PNM/Tucson at 10–12.

[433] Allegheny Energy at 9–10; Xcel at 16–17.

[434] Indianapolis P&L at 6–7.

[435] We observe that specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations have involved transactions with affiliates. *See Idaho Power Company, et al.*, 103 FERC ¶ 61,182 (2003) (settlement of, among other issues, a practice whereby a transmission provider permitted its merchant function to request non-firm transmission to enable the merchant function to make off-system sales that by definition were not used to serve native load, so that the transmission did not qualify for the ''native load'' priority specified in section 28.4 of the transmission provider's OATT); *Cleco Corporation, et al.*, 104 FERC ¶61,125 (2003) (settlement between Enforcement staff and a transmission provider (and others in the corporate family) that provided a unique type of transmission service for its affiliate that was neither made available to non-affiliates nor included in its FERC tariff); *Tucson Electric Power Company,* 109 FERC ¶ 61,272 (2004) (operational audit in which staff found that, among other matters, a transmission provider permitted its wholesale merchant function to purchase hourly non-firm and monthly firm point-to-point transmission service using an off-OASIS scheduling procedure while the transmission provider did not post on its OASIS the availability of capacity on these paths); *South Carolina Electric & Gas Company, et al.*, 111 FERC ¶ 61,217 (2005) (settlement of Enforcement staff allegation that a transmission provider made available firm point-to-point transmission service to its affiliated merchant function that did not submit

Continued

As a result, we believe that it is appropriate to establish a rebuttable presumption that if we find that a transmission provider should lose its market-based rate authority in a particular market, all affiliates of the transmission provider should also lose their market-based rate authority in the same market.

426. We are mindful, however, that the circumstances of a particular affiliate may not always justify the imposition of a remedy so severe as revocation of market-based rate authority in a particular market when its affiliated transmission provider loses its market-based rate authority in that market as a result of an OATT violation. To ensure that a determination to revoke market-based rate authority in a particular market for a transmission provider and all of its affiliates that possess such authority is adequately based upon record evidence, we will allow an opportunity for each such affiliate to make a showing that it should retain its market-based rate authority or that enforcement action against it should be less severe than revocation. The determination whether an affiliate has overcome the rebuttable presumption depends on an analysis of specific facts in the record. Relevant facts would include, for example, whether (1) The affiliate knew of, participated in, or was an accomplice to the OATT violation, (2) the affiliate assisted the transmission provider in exercising market power, or (3) the affiliate benefited from the violation.

427. Consistent with our approach to revocation of a transmission provider's market-based rates, the Commission clarifies that a decision to revoke the market-based rate authority of the transmission provider's affiliates in the affected market will also be based on a finding that the transmission provider's violation of its OATT has a nexus to the market-based rate authority of those affiliates.

transmission schedules with specific receipt points for the service as required by section 13.8 of the transmission provider's OATT); and *MidAmerican Energy Company,* 112 FERC ¶ 61,346 (2005) (operational audit in which staff found, among other things, that a transmission provider permitted its wholesale merchant function to (a) Use network transmission service to bring short-term energy purchases onto its system while it simultaneously made off-system sales, inconsistently with the preamble to Part III of the transmission provider's OATT and section 28.6 of its OATT; and (b) confirm firm network transmission service requests without identifying a designated network resource or acquiring an associated network resource, in some instances using this service to deliver short-term energy purchases used to facilitate off-system sales, inconsistent with section 29.2 or section 30.6 of the transmission provider's OATT).

2. Other Barriers to Entry

Commission Proposal

428. The Commission proposed in the NOPR that, in order for a seller to demonstrate that it satisfies the Commission's vertical market power concerns, it must demonstrate that neither it nor its affiliates can erect other barriers to entry (*i.e.*, barriers other than transmission). In this regard, the Commission proposed to continue to require a seller to provide a description of its affiliation, ownership or control of inputs to electric power production (*e.g.*, fuel supplies within the relevant control area); ownership or control of gas storage or intrastate transportation or distribution of inputs to electric power production; and ownership or control of sites for new generation capacity development. The Commission also proposed to require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and that they cannot do so.

429. In addition, the Commission proposed to provide additional regulatory certainty by clarifying which inputs to electric power production the Commission will consider as other barriers to entry in its vertical market power review, and sought comments on this proposal. Specifically, the Commission proposed that the analysis continue to include the consideration of ownership or control of sites for development of generation in the relevant market, fuel inputs such as coal facilities in the relevant market, and the transportation, storage or distribution of inputs to electric power production such as intrastate gas storage and distribution systems, and rail cars/barges for the transportation of coal.

430. The Commission also clarified that sellers need not address interstate transportation of natural gas supplies because such transportation is regulated by this Commission.[436] The Commission explained that its open access regulations adequately prevent sellers from withholding interstate pipeline capacity. In addition, interstate pipeline capacity held by firm shippers that is not utilized or released is available from the pipeline on an interruptible basis. As to the commodity, the Commission noted that Congress has found the natural gas market competitive.[437]

431. The Commission also sought comment on whether ownership or control of other inputs to electric power production should be considered as potential barriers to entry and, if so, what criteria the Commission should use to evaluate evidence that is presented.

Comments

432. Several commenters state that the Commission's other barriers to entry criteria are long-standing, well established and thus no expansion of current policy is necessary.[438] They submit that the requirement that the analysis include the consideration of ownership or control of sites for development of generation in the relevant market, fuel inputs such as coal supplies in the relevant market, and the transportation, storage or distribution of inputs to electric power production such as intrastate gas storage and distribution systems, and rail cars/barges for the transportation of coal, is broad and provides sufficient information for the Commission to assess the seller's potential to erect barriers to entry. They assert that this information, coupled with the proposal to require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and that they cannot do so, provides the Commission with appropriate information.[439]

433. APPA/TAPS suggest that the proposed entry barriers affirmation should be signed and affirmed by a senior corporate official.[440] However, APPA/TAPS state that the Commission should not codify the specific entry barriers that it will consider given the ever-changing nature of electricity markets.[441] They submit that while illustrations of entry barriers can provide guidance to sellers and market participants, the Commission should not limit the kinds of entry barriers it will consider.

434. Sempra states that, to the extent the new analytic framework (the consolidation of the former transmission market power and other barriers to entry factors into the vertical market power analysis) would recognize existing

[436] NOPR at P 93 (citing *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles January 1991–June 1996 ¶ 30,939 (Apr. 8, 1992)).

[437] NOPR at P 93 (citing Natural Gas Wellhead Decontrol Act of 1989, Pub. L. 101–60, 103 Stat. 157 (1989); Natural Gas Policy Act of 1978, section 601(a)(1), 15 U.S.C. 3431 (deregulating the wellhead price of natural gas)).

[438] Allegheny Energy at 9–10; Southern at 38–40; EEI at 44–45.

[439] *See, e.g.*, New Jersey Board at 3.

[440] APPA/TAPS at 6, 85.

[441] APPA/TAPS at 6, 84–85.

precedent and not work to place additional burdens on market-based rate sellers, Sempra would support it.[442]

435. Several sellers support continuation of the Commission's policy that sellers need not address natural gas and its interstate transportation as part of their vertical market power analysis.[443] In contrast, a commenter states that the Commission should not make a blanket exemption for sellers or their affiliates who own or control natural gas pipeline capacity. Notwithstanding the Commission's statement that natural gas interstate pipelines are regulated by the Commission and that the regulations adequately prevent sellers from withholding capacity, this commenter argues that the natural gas open access rules do not adequately mitigate vertical market power in all situations. It encourages the Commission to require sellers with significant firm interstate pipeline capacity rights to demonstrate that they do not have vertical market power.[444]

436. APPA/TAPS state that the Commission should clarify that it will consider control over interstate natural gas transportation if the issue is raised in a market-based rate proceeding.[445] APPA/TAPS state that even if sellers do not have to address interstate gas transportation as part of the vertical market power test, intervenors should not be precluded from raising concerns and introducing evidence regarding a seller's position in the interstate natural gas transportation market as a potential entry barrier and APPA/TAPS seek clarification in this regard.[446]

437. Several commenters state that the markets for the other inputs to generation factor (*e.g.*, fuel supply other than natural gas, transportation and storage) are workably competitive and provide few opportunities for a seller to raise entry barriers. They therefore suggest that the Commission create a rebuttable presumption that the markets for other factor inputs such as coal, oil and distillate commodity markets, the transportation and storage of these fuels, sites for new plants, etc., are workably competitive. They urge that, absent a showing to the contrary, ownership or control of such assets need not be analyzed.[447] In this regard, Duke states that the Commission should allow sellers to make the representation that they cannot erect such barriers, while allowing other parties to introduce evidence challenging such an assertion.[448]

438. PG&E states that, similar to the rules for interstate transportation of natural gas supplies (under which Commission open access regulations adequately prevent sellers from withholding interstate gas pipeline capacity), State regulation of access to gas storage, natural gas pipelines, or natural gas distribution should be a basis for finding that an entity with ownership or control of such assets cannot erect barriers to entry or otherwise hold or exercise vertical market power in the generation market.[449]

439. SoCal Edison urges the Commission to clarify that, with regard to sites for building generation, mere ownership of real estate does not reasonably support an inference of a barrier to entry, and that sellers are not required, in the first instance, to make any affirmative demonstration of the absence of potential that their real estate holdings might constitute a theoretical barrier to entry. Rather, the Commission should clarify that it would pursue such inquiry only to the extent colorable issues are raised by way of protest or intervention.[450] Sempra states the Commission should modify the regulatory text in three respects. First, the Commission should explicitly exclude from the definition of ''inputs to electric power production'' in proposed § 35.36(a)(4) interstate transportation of natural gas supplies (both ownership/control of facilities as well as ownership/control of capacity) and the gas commodity itself. Second, the Commission should also exclude from the definition of ''inputs to electric power production'' intrastate natural gas facilities or distribution facilities, particularly where such facilities are operated under pervasive State regulations and in accordance with open access principles. Third, the Commission should make clear in this provision and at § 35.27(e) of its proposed regulations (pertaining to a seller's vertical market power analysis), that the only ''inputs'' that need to be addressed are those present in the seller's relevant geographic market(s).[451]

Commission Determination

440. As discussed above, the Commission will adopt the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but we will modify the requirements when addressing other barriers to entry. We also provide clarification below regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry) and we modify the proposed regulatory text in that regard.

441. In this rule, the Commission draws a distinction between two categories of inputs to electric power production: One consisting of natural gas supply, interstate natural gas transportation (which includes interstate natural gas storage), oil supply, and oil transportation, and another consisting of intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.

442. With regard to the first category, based upon the comments received and further consideration, the Commission will not require a description or affirmative statement with regard to ownership or control of, or affiliation with an entity that owns or controls, natural gas and oil supply, including interstate natural gas transportation and oil transportation.

443. In the case of natural gas, prices for wellhead sales were decontrolled by Congress.[452] Further, the Commission has granted other sellers blanket authority to make sales at market rates. In the case of transportation of natural gas, pipelines operate pursuant to the open and non-discriminatory requirements of Part 284 of the Commission's regulations.[453] These regulations mandate that all available pipeline capacity be posted on the pipelines' Web site, and that available capacity cannot be withheld from a

[442] Sempra at 6–7.

[443] *See* Constellation at 25; Duke at 30; PG&E at 13; Sempra at 6.

[444] Drs. Broehm and Fox-Penner at 14–15.

[445] APPA/TAPS at 82–85.

[446] APPA/TAPS at 6.

[447] *See, e.g.*, Duke at 30–32; Constellation at 23–27.

[448] Duke at 30–32.

[449] *See* PG&E at 3, 13–14.

[450] SoCal Edison at 2, 19.

[451] Sempra at 6.

[452] *INGAA* v. *FERC*, 285 F.3d 18 (D.C. Cir. 2002); Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989).

[453] *See, e.g., Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles January 1991–June 1996 ¶ 30,939 (Apr. 8, 1992); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,091 (Feb. 9, 2000); *order on reh'g*, Order No. 637–A, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000) ¶ 31,099 (May 19, 2000); *reh'g denied*, Order No. 637–B, 92 FERC ¶ 61,062 (2000); *aff'd in part and denied in part.*

shipper willing to pay the maximum approved tariff rate.

444. Similarly, we note that oil pipelines are common carriers under the Interstate Commerce Act, specifically under section 1(4), and are required to provide transportation service ''upon reasonable request therefore'' [454] and that Congress has not chosen to regulate sales of oil.

445. In response to APPA/TAPS' request for clarification, we note that as an initial matter, to the extent intervenors are concerned about a seller's market power from ownership or control of interstate natural gas transportation, this would be actionable first in a complaint proceeding under section 5 of the Natural Gas Act before turning to market-based rate consequences.

446. With regard to the second category, in light of the comments received, and upon further consideration, the Commission adopts a rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[455] To date, the Commission has not found such ownership, control or affiliation to be a potential barrier to entry warranting further analysis in the context of market-based rate proceedings. However, unlike the first category of inputs, the Commission does not have sufficient evidence to remove these inputs from the analysis entirely. Accordingly, we will rebuttably presume that ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars do not allow a seller to raise entry barriers, but will allow intervenors to demonstrate otherwise. We note that this rebuttable presumption only applies if the seller describes and attests to these inputs to electric power production, as described herein.

447. With regard to this second category of inputs to electric power production, we will require a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars. The Commission will require sellers to provide this description and to make an affirmative statement, with some modifications to the affirmative statement from what was proposed in the NOPR. Instead of requiring sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market, we will require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. We clarify that the obligation in this regard applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.

448. We therefore modify the proposed regulations to require a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and rail cars, to ensure that this information is included in the record of each market-based rate proceeding. In addition, a seller is required to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

449. While some commenters raise concerns that codification of these possible barriers may inappropriately limit the analysis of a seller's potential to erect other barriers to entry, we clarify that we are codifying what showing a seller must make in order to receive authority to make sales of electric power at market-based rates. By so doing, we are not preventing intervenors from raising other barriers to entry concerns for consideration on a case-by-case basis. This approach will allow unique or newly developed barriers to entry to be brought before the Commission.

450. We will not adopt APPA/TAPS' proposal that the affirmation be signed and affirmed by a senior corporate officer. Section 35.37(b) of the Commission's regulations requires sellers to ''provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission * * *''.[456] The Commission has ample authority to enforce its regulations, and therefore does not believe that it is necessary in these circumstances to require the affirmative statement to be signed by a senior corporate official.

451. The changes made to the evaluation of other barriers to entry, as described above, should not be more burdensome on market-based rate sellers than that which is currently in place. For the most part, the Commission is maintaining its current policy, with some variation and additional guidance on what is required. The policy adopted in this Final Rule should provide sellers with additional clarity regarding what needs to be addressed as a potential other barrier to entry and the way in which to address it.

3. Barriers Erected or Controlled by Other Than The Seller

Comments

452. APPA/TAPS state that entry conditions and barriers, regardless of origin, need to be considered in both the horizontal and vertical market power tests.[457] APPA/TAPS state that the Commission should not focus solely on entry barriers erected by the seller itself and that the Commission must be receptive to claims that entry barriers in the seller's market provide or enhance market power, even if the seller itself did not erect the barriers.[458] Another commenter states that the Commission should maintain a separate evaluation on other barriers to entry that are not caused by a seller, thus requiring a seller to address barrier to entry issues to the relevant market, even if those barriers are not caused by a seller or its affiliates.

Commission Determination

453. The Commission finds that it is not reasonable to routinely require sellers to make a showing regarding potential barriers to entry that others might erect and that are beyond the seller's control. However, we will allow intervenors to present evidence in this regard, and by this means we will be able to assess the existence of barriers to entry beyond the seller's control but which may affect the seller's ability to exercise market power. Should a potential barrier in the relevant market

[454] 49 App. U.S.C. 1(4).

[455] We modify the definition of ''inputs to electric power production'' in 18 CFR 35.36(a)(4) to reflect this clarification.

[456] 18 CFR 35.41(b) (formerly 18 CFR 35.37(b)).

[457] APPA/TAPS at 6.

[458] APPA/TAPS at 82–84.

be raised by an intervenor, the Commission will address such claims on a case-by-case basis.

4. Planning and Expansion Efforts

454. In the NOPR, the Commission noted that several commenters had suggested that a transmission planning and expansion process can ameliorate vertical market power, and, accordingly, the Commission was seeking comment on the issues of transmission planning and expansion in the notice of proposed rulemaking in the OATT Reform Rulemaking. The Commission sought comment in the NOPR on whether the planning and expansion efforts in the OATT Reform Rulemaking would address commenters' concerns here.

Comments

455. APPA/TAPS state that there will be a continuing need to address transmission market power issues, even after adoption of a revised *pro forma* OATT, because the improvements in transmission planning and expansion will not be immediately felt.[459] EPSA states that it advocates robust, independent and mandatory regional planning as a means to combat vertical market power and ensure competitive markets.[460]

456. TDU Systems recommend that the Commission revoke a transmission provider's market-based rate authority if it fails to build transmission to accommodate the needs of its transmission customers demonstrated through an open, joint planning process.[461] TDU Systems submit that willful failure to plan, maintain and expand the transmission system to meet transmission customers' needs is an abuse of vertical market power and creates structural barriers to competition.

457. ELCON states that while it is encouraged by proposals in the OATT Reform Rulemaking, it recommends that transmission market power be the subject of a new rulemaking.[462] Similarly, EPSA asserts that a technical conference to develop the barriers to entry portion of the screens would help ensure an open, accessible, and robust competitive market.[463]

Commission Determination

458. We find that our reforms to the *pro forma* OATT to require coordinated transmission planning on a local and regional level address the concerns raised by commenters. While we recognize that the transmission planning reforms in Order No. 890 are still in the process of being implemented, failure to plan, maintain and expand the transmission system in accordance with the applicable, Commission-approved OATT has always been, and will continue to be, an OATT violation. Order No. 890 provides for revocation of an entity's, and possibly that of its affiliates, market-based rate authority in response to an OATT violation upon a finding of a specific factual nexus between the violation and the entity's market-based rate authority.[464] Should such a violation occur, the Commission will address it in that context. The Commission does not find that the need exists to convene a technical conference in this regard. The OATT Reform Rulemaking dealt extensively with this issue and the Commission finds that it has been adequately addressed in Order No. 890.

5. Monopsony Power

459. In the NOPR, the Commission sought comment on whether the exercise of buyer's market power by the transmission provider should be considered a potential barrier to entry and, if so, what criteria the Commission should use to evaluate evidence that is presented.

Comments

460. Allegheny states that the NOPR provided no explanation for why a transmission provider's buyer's market power should be relevant to the analysis.[465] EEI argues that the Commission should not consider buyer's market power as a barrier to entry because it is not relevant to the analysis. According to EEI, the market-based rate analysis considers the ability of the applicant to exercise market power as a seller, not a buyer, which is consistent with the Commission's authority under section 205 of the FPA, which regulates the sale of electricity. EEI asserts that states generally have jurisdiction over the purchase of electricity by franchised utilities.[466]

461. EPSA argues that if a utility holds a dominant purchasing position in the wholesale marketplace that allows it to exert excessive and discretionary buying power (of both supply and supply generation facilities), the exercise of market power will then lie with the buyer, not the seller. This problem is exacerbated when such a purchasing utility also owns, controls or dispatches its own proprietary supply and the relevant transmission system.

462. EPSA states that some would argue that the Commission cannot order economic dispatch or competitive solicitation because the FPA grants the Commission jurisdiction over sales, not purchases. However, EPSA submits that the Commission would not be mandating purchases, but eliminating the exercise of market power which directly raises the prices for wholesale sales. In so doing, the Commission would be using its tools under sections 205 and 206 of the FPA to ensure just and reasonable wholesale rates by allowing competitive alternatives to enter the market and protecting consumers from practices that will result in excessive rates and charges. EPSA argues that the Commission must develop a transparent, methodical process for assessing this segment of the vertical market power analysis. EPSA submits that load serving entities that are transmission providers must, in addition to providing enhanced transmission services, facilitate accessible long-term markets through all-source competitive procurement processes, preferably via state created and supervised means, with independent third party oversight. It asserts that the Commission must achieve and ensure these goals through a transparent, well-developed process. EPSA requests that the Commission convene a technical conference in order to fully develop that process and ensure that barriers to entry are properly mitigated.[467]

Commission Determination

463. EPSA's proposal not only raises jurisdictional issues, but EPSA has failed to provide specific instances in which the exercise of monopsony power has taken place and has provided no guidance as to how buyer market power should be measured (even assuming the Commission has jurisdiction to address it). The Commission does not believe it is appropriate to attempt to address these difficult issues without specific evidence of monopsony power and a clear delineation of the State-Federal jurisdiction issues that would arise in the context of a specific seller and specific set of circumstances. For the same reason, we will not grant EPSA's request to convene a technical conference to address such issues generically. Until EPSA or others provide such information concerning a particular seller in either a market-based

[459] APPA/TAPS at 80–85.

[460] EPSA at 27.

[461] TDU Systems at 21–23.

[462] ELCON at 5–6.

[463] EPSA at 28.

[464] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1743, 1747.

[465] Allegheny Energy at 10.

[466] EEI at 43.

[467] EPSA at 26–27.

rate proceeding or a complaint, we defer judgment on the many difficult issues raised by EPSA.

C. Affiliate Abuse

1. General Affiliate Terms and Conditions

a. Codifying Affiliate Restrictions in Commission Regulations

Commission Proposal

464. In the NOPR the Commission proposed to discontinue referring to affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead proposed to codify in the regulations at 18 CFR part 35, subpart H, an explicit requirement that any seller with market-based rate authority must comply with the affiliate power sales restrictions and other affiliate restrictions. The Commission proposed to address affiliate abuse by requiring that the conditions set forth in the proposed regulations be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. The Commission indicated that a seller seeking to obtain or retain market-based rate authority will be obligated to provide a detailed description of its corporate structure so that the Commission can be assured that the Commission's requirements are being applied correctly. In particular, the Commission proposed that sellers with franchised service territories be required to make a showing regarding whether they serve captive customers and to identify all ''non-regulated'' power sales affiliates, such as affiliated marketers and generators.[468]

465. The Commission further proposed that, as a condition of receiving market-based rate authority, sellers must adopt the MBR tariff (included as Appendix A to the NOPR) which includes a provision requiring the seller to comply with, among other things, the affiliate restrictions in the regulations. The Commission noted that failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation. The Commission sought comment on these proposals

Comments

466. As a general matter, commenters support the Commission's proposal to codify the affiliate restrictions in the Commission's regulations.[469] No comments were received opposing the proposal to codify affiliate restrictions in the Commission's regulations.

Commission Determination

467. The Commission will adopt the proposal in the NOPR to discontinue considering affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead codify in the Commission's regulations in § 35.39 an explicit requirement that any seller with market-based rate authority must comply with the affiliate restrictions. This will address affiliate abuse by requiring that the conditions set forth in the regulations be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. Included in the regulations will be a provision expressly prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates without first receiving Commission authorization for the transaction under section 205 of the FPA. Also included in the regulations will be the requirements that have previously been known as the market-based rate ''code of conduct,'' as those requirements have been revised in this Final Rule.

468. Additionally, although we do not adopt the proposal to require that, as a condition of receiving market-based rate authority, sellers must adopt the MBR tariff (included as Appendix A to the NOPR), we do adopt a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff, including a provision requiring the seller to comply with, among other things, the affiliate restrictions in the regulations. We further adopt the proposal that failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation.

b. Definition of ''Captive Customers''

Commission Proposal

469. The Commission stated in the NOPR that, among other things, in the Commission's Final Rule on transactions subject to section 203 of the FPA, the Commission defined the term ''captive customers'' to mean ''any wholesale or retail electric energy customers served under cost-based regulation.''[470] The Commission sought comment on whether the same definition should be used for purposes of this rule.

Comments

470. While a number of commenters support the Commission's proposal to codify the affiliate abuse ''prong'' in the Commission's regulations,[471] they comment that the proposed affiliate abuse restrictions do not do enough to protect retail customers from affiliate abuse.[472] NASUCA argues that affiliate abuse restrictions should be applicable to any affiliate with any retail customers, whether or not the retail affiliate is a ''franchised'' utility, whether or not it has a State-imposed ''service obligation,'' and whether or not its customers are characterized as ''captive.'' NASUCA submits that the Commission should not rely on a State's adoption of a retail access regime for any determination that a customer is not captive. Further, although NASUCA comments that the Commission's proposed definition for ''captive customers'' is an improvement from the text of the proposed regulation (which contains no definition of ''captive customers''), NASUCA suggests it could also invite distinctions turning on the meaning of ''cost-based regulation'' that might cause future uncertainty in some circumstances and a corresponding loss of customer protection.[473]

471. New Jersey Board argues that when customers lack realistic alternatives to purchasing power from their local utility, regardless of a legal right to competitive power suppliers, such customers are still captive. New Jersey Board states that most customers in retail choice states still rely on the provider-of-last-resort for electric service and, thus, are still captive customers.[474] New Jersey Board comments that, due to the relatively young retail choice and deregulation programs in many states, ''it would be premature to declare electric retail choice to be vibrant enough to leave consumer protection from affiliate abuses completely to the marketplace.''[475] New Jersey Board states that, even where there are a few

[468] In the NOPR, the Commission proposed to use the term ''non-regulated power sales affiliate.'' As discussed below, this Final Rule uses the term ''market-regulated power sales affiliate'' instead. ''Market-regulated'' power sales affiliates, for purposes of this rule, refers to sellers that sell at market-based rates rather than cost-based rates. If such sellers are public utilities, technically, they are not unregulated since they must receive market-based rate authority from the Commission and are subject to ongoing oversight by the Commission. See discussion *infra.*

[469] *See generally* APPA/TAPS at 7; 85–86.

[470] *Transactions Subject to FPA section 203,* Order No. 669–A, 71 FR 28422 (May 16, 2006), FERC Stats. & Regs. ¶ 31,214 (2006). *See also Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005,* Order No. 667–A, 71 FR 28446 (May 16, 2006), FERC Stats. & Regs. ¶ 31, 213 (2006).

[471] New Jersey Board at 3.

[472] NASUCA at 20–30.

[473] NASUCA at 20–30.

[474] New Jersey Board reply comments at 3–4.

[475] *Id.* at 5.

providers that comprise the market, such oligopolies often exhibit the same lack of competition and high prices as are seen in a monopoly market. Thus, affiliate abuse would remain a concern where utilities would be granted market-based rate authority.[476]

472. AARP similarly comments that the proposed definition of ''captive customers'' fails to capture the potential for adverse impacts on retail customers of ''default'' suppliers and thus, the coverage of the Commission's affiliate restrictions should be expanded to prevent customers from bearing the costs of non-regulated marketing affiliates of the public utility they rely on for reliable service.[477]

473. ELCON suggests that ''captive customers'' should be defined as any end-users that do not have real competitive opportunities.[478] It recommends that the Commission adopt a case-specific approach to identifying captive customers to account for the failure of retail competition in many restructured states.

474. A number of other commenters argue that the proposed definition of ''captive customers'' is too broad[479] and would improperly include customers with competitive alternatives. They state that the Commission should clarify that ''captive customers'' does not include customers in states with retail choice.[480] Duke recommends that the Commission define ''captive customer'' as ''any electric energy customer that cannot choose an alternative energy supplier.''[481] Duke adds that initial commenters, such as ELCON, provide no support for their assertion that state retail access programs do not generate effective competition and that most provider-of-last-resort customers are actually captive.

475. Ameren comments that while there are sellers with market-based rate authority that have no captive wholesale customers for energy, but do have a cost-based rate schedule for reactive power supply, the fact that a seller has wholesale customers under a single cost-based rate for reactive power should not render the entity a seller with ''captive customers'' and therefore, subject to the affiliate restrictions.[482] It states that such a seller would have no ability to transfer benefits from its ''captive customers'' (customers taking reactive power services at cost-based rates) to subsidize its unregulated market-based rate sales, given the different products at issue and the restrictions of the cost-based rates for reactive power.

476. APPA/TAPS submit that the definition of ''captive customers'' should include wholesale transmission customers captive to the transmission provider's system.[483] APPA/TAPS state that affiliate abuse not only raises costs to wholesale customers, it can also harm competition such as through cross-subsidization that provides the seller with an unfair competitive advantage. Therefore, APPA/TAPS state that wholesale transmission customers captive to the transmission provider's system are particularly vulnerable to this kind of competitive harm and should be included in the definition of ''captive customers'' in the regulations.[484]

477. EEI responds to APPA/TAPS' comment by stating that it is ''completely unnecessary'' to include transmission dependent utilities in the definition of captive customers since Order No. 888 already provides sufficient protections for transmission customers. Additionally, EEI replies that transmission dependent utilities are like customers with retail choice who have chosen to stay under cost-based rates while other transmission customers have broader options. EEI responds that the Commission does not currently consider such customers captive and there is no reason to change this policy.[485]

Commission Determination

478. The Commission adopts the NOPR proposal to define ''captive customers'' as ''any wholesale or retail electric energy customers served under cost-based regulation.''

479. The Commission clarifies in response to several comments that the definition of ''captive customers'' does not include those customers who have retail choice, *i.e.* the ability to select a retail supplier based on the rates, terms and conditions of service offered. Retail customers who choose to be served under cost-based rates but have the ability, by virtue of State law, to choose one retail supplier over another, are not considered to be under ''cost-based regulation'' and therefore are not ''captive.''

480. As the Commission has explained, retail customers in retail choice states who choose to buy power from their local utility at cost-based rates as part of that utility's provider-of-last-resort obligation are not considered captive customers because, although they may choose not to do so, they have the ability to take service from a different supplier whose rates are set by the marketplace. In other words, they are not served under cost-based regulation, since that term indicates a regulatory regime in which retail choice is not available.[486] On the other hand, in a regulatory regime in which retail customers have no ability to choose a supplier, they are considered captive because they must purchase from the local utility pursuant to cost-based rates set by a State or local regulatory authority.[487] Therefore, with this clarification, the Commission will adopt the definition of ''captive customers'' proposed in the NOPR and clarifies, that, as the Commission did in Order No. 669–A, we will include the definition of captive customers in the regulations. Regarding wholesale customers, sellers should continue to explain why, if they have wholesale customers, those customers are not captive.

481. We note that it is not the role of this Commission to evaluate the success or failure of a State's retail choice program including whether sufficient choices are available for customers inclined to choose a different supplier. In this regard, the states are best equipped to make such a determination and, if necessary, modify or otherwise revise their retail access programs as they deem appropriate. Further, to the extent a retail customer in a retail choice state elects to be served by its local utility under provider-of-last-resort obligations, the State or local rate setting authority, in determining just and reasonable cost-based retail rates, would in most circumstances be able to review the prudence of affiliate purchased power costs and disallow pass-through of costs incurred as a result of an affiliate undue preference.

482. We also decline to include transmission customers in the definition of ''captive customers'' for purposes of market-based rates. We agree with EEI that the Commission's open access

[476] *Id.*

[477] AARP at 10–11.

[478] ELCON at 2, 7–8.

[479] Ameren at 11–14; Allegheny at 12–13; EEI at 44; FirstEnergy at 13; Duke at 4, 32; and Duquesne at 4.

[480] Constellation argues that customers are not to be considered ''captive'' and a seller is therefore not considered a franchised public utility when a retail choice program is in place for the public utility's retail customers. Constellation at 4.

[481] Duke at 32–36. Duke reply comments at 22–23.

[482] Ameren at 12.

[483] APPA/TAPS at 7, 86–87.

[484] *Id.* at 86–87.

[485] EEI reply comments at 35–36.

[486] *Duquesne Light Holdings, Inc.*, 117 FERC ¶ 61,326 at P 38 (2006).

[487] Where a utility has captive retail customers, but industrial customers have retail choice, we would consider that utility to have captive customers because the retail residential customers are captive.

policies protect transmission customers from the exercise of vertical market power. In this regard, we note that the Commission recently issued Order No. 890, which revised the *pro forma* OATT to ensure that it achieves its original purpose of remedying undue discrimination. Order No. 890 provided greater clarity regarding the requirements of the *pro forma* OATT and greater transparency in the rules applicable to the planning and use of the transmission system, in order to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement of the tariff.

483. In response to Ameren's comments that a seller with wholesale customers under a single cost-based rate for reactive power should not be considered a seller with ''captive customers'' subject to the affiliate restrictions, we agree that such customers are not captive for purposes of market-based rates. The concerns underlying the affiliate restrictions do not apply to sales of reactive power because those sales are typically either made to transmission providers so that the transmission provider can satisfy its obligation to provide reactive power or made by the transmission provider under its applicable OATT.

c. Definition of ''Non-Regulated Power Sales Affiliate''

Commission Proposal

484. Proposed § 35.36(a)(6) defined ''non-regulated power sales affiliate'' as ''any non-traditional power seller affiliate, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are not regulated on a cost basis under the FPA.''

Comments

485. A number of commenters seek clarification and modification of the Commission's proposed definition of ''non-regulated power sales affiliate.''

486. Southern requests clarification that a franchised public utility does not become a non-regulated power sales affiliate simply because it may make some wholesale sales under market-based rate authority.

487. SoCal Edison argues that the Commission offers no explanation for including Qualifying Facilities (QFs) in the definition of ''non-regulated power sales affiliate.'' It states that the proposed definition of non-regulated power sales affiliate would subject QFs that may not have market-based rate authority to the code of conduct. It states that the NOPR proposal would constitute a departure from traditional PURPA implementation and from the Commission's recently revised regulations reaffirming that QF contracts created pursuant to a statutory regulatory authority's implementation of PURPA are exempt from review under sections 205 and 206 of the FPA.[488] PG&E asserts that the Commission should clarify the meaning of ''non-regulated power sales affiliate'' so that it does not encompass all affiliates such as parent companies or the natural gas LDC function of the regulated, franchised utility.[489]

488. Xcel states that it is not clear whether the following result was intended, but the definition arguably could cover a ''traditional'' utility with a franchised retail service territory that had converted all of its wholesale sales from cost-based to market-based rates. According to Xcel, not all utilities will be selling at cost-based rates at wholesale, even though they may still be doing so at retail in franchised service territories.[490] Xcel does not believe that it would be reasonable to exclude from the definition of ''non-regulated power sales affiliate'' a utility that serves retail customers under a franchised service territory. Xcel also comments that the Commission should allow a waiver provision for utilities' subsidiaries or affiliates to be treated under the Commission's affiliate sales rules as affiliated utilities rather than as ''non-regulated power sales affiliates.''[491] Xcel believes that the proposed definition would generally serve to demarcate affiliates that should be treated as regulated from those that should be treated as non-regulated under the Commission's affiliate rules but states that it is not desirable or beneficial to draw a completely bright line between the two. Xcel states that some flexibility may be beneficial for both utilities and their customers and the Commission should not foreclose innovative structures by adopting hard and fast rules.[492]

489. NASUCA also suggests revisions to this definition, out of concern that several of the terms used (non-regulated, non-traditional, regulated on a cost basis) are vague, inaccurate and unnecessary.[493] NASUCA suggests that the term be renamed ''power sales affiliate with market-based rates'' and defined as ''any power seller affiliate utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, with market-based rates authorized under these rules or Commission orders.''[494]

Commission Determination

490. The Commission will modify the definition of ''non-regulated power sales affiliate,'' and change the term to ''market-regulated power sales affiliate.''[495] In response to various commenters, we clarify that this definition is intended to apply only to non-franchised power sales affiliates (whose power sales are not regulated on a cost basis under the FPA, *e.g.*, affiliates whose power sales are made at market-based rates) of franchised public utilities. Additionally, while we recognize that we have used the term ''non-regulated'' in the past, we believe that ''market-regulated'' is a more appropriate description for the entities we intend to capture in this definition. Accordingly, in this Final Rule, we revise the definition of ''market-regulated power sales affiliate'' to mean ''any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part at market-based rates.'' Because the revised definition includes only non-franchised public utilities, it does not apply to a franchised public utility that makes some sales at market-based rates.[496]

491. Xcel posits a somewhat different scenario under which it believes that a franchised public utility would fall within the definition of ''non-regulated power sales affiliate,'' namely, if such utility makes no wholesale sales that are regulated on a cost basis (making only wholesale sales at market-based rates) but serves retail customers under a franchised service territory. With the revision to the definition of ''market-regulated power sales affiliate'' that we adopt here, such a utility would not fall within the definition of ''market-regulated power sales affiliate'' since it has a franchised service territory.

492. In addition, we note that the Commission has historically placed affiliate restrictions only on the

[488] SoCal Edison at 4–6.

[489] PG&E at 14–21.

[490] Xcel at 15.

[491] *Id.*

[492] *Id.* at 16.

[493] NASUCA at 30.

[494] *Id.* at 30.

[495] NOPR at Proposed Regulations at 18 CFR 35.36(a)(6). We adopt this regulation at 18 CFR 35.36(a)(7).

[496] However, under the standards of conduct, a wholesale merchant function that engages in such sales must function independently of the utility's transmission function. 18 CFR 358(d)(3) and 18 CFR 358.4(a)(1).

relationship between a franchised public utility with captive customers and any affiliated market-regulated power sales affiliate. Nevertheless, we believe that there may be circumstances in which it also would be appropriate to impose similar restrictions on the relationship of two affiliated franchised public utilities where one of the affiliates has captive customers and one does not have captive customers. In such a case, there is a potential for the transfer of benefits from the captive customers of the first franchised utility to the benefit of the second franchised utility and ultimately to the joint stockholders of the two affiliated franchised public utilities. Commenters in the instant proceeding did not address the potential for affiliate abuse in this situation (*i.e.*, between a franchised public utility with captive customers and an affiliated franchised public utility without captive customers). Accordingly, we do not generically impose the affiliate restrictions on such relationships but will evaluate whether to impose the affiliate restrictions in such situations on a case-by-case basis.

493. However, to avoid confusion between references to a ''franchised public utility with captive customers'' and a ''franchised public utility without captive customers'' we will revise the definition of ''franchised public utility'' in § 35.36(a)(5) to remove the reference to captive customers. Accordingly, ''franchised public utility'' will be defined as ''a public utility with a franchised service obligation under State law.'' Further, we will revise other sections of the affiliate restrictions to specifically use the term ''franchised public utility with captive customers'' to clarify when the affiliate restrictions apply.

494. Additionally, not all qualifying facilities are necessarily included in the proposed definition of ''market-regulated power sales affiliate.'' Only those qualifying facilities whose market-based rate sales fall under the Commission's jurisdiction would fall within the definition of ''market-regulated power sales affiliate.'' To the extent that some of a qualifying facility's sales are regulated under the FPA, even if other sales are regulated by the states, such a qualifying facility would be considered a market-regulated power sales affiliate by virtue of its FPA jurisdictional sales.

495. Additionally, the Commission clarifies that the definition of ''market-regulated power sales affiliate'' does not encompass all affiliates such as parent companies or the natural gas LDC function of the regulated franchised utility; rather, it only includes non-franchised, power sales affiliates (sellers) that sell power in whole or in part at market based rates, and not an affiliated service company or others who are not authorized to make sales of power.

d. Other Definitions

In the NOPR, the Commission proposed to adopt a restriction on affiliate sales of electric energy, whereby no wholesale sale of electric energy could be made between a public utility seller with a franchised service territory and a non-regulated power sales affiliate without first receiving Commission authorization under FPA section 205. This restriction would be a condition of obtaining and retaining market-based rate authority, and a failure to satisfy that condition would be a violation of the seller's market-based rate tariff.[497]

Comments

496. Constellation proposes that the language in the proposed affiliate sales restriction provision be amended to use the defined term ''franchised public utility'' by replacing the phrase ''public utility Seller with a franchised service territory'' with ''Seller that is a franchised public utility.'' Constellation submits that this change would make clear that the affiliate restrictions apply only if the seller is affiliated with a public utility that has captive customers, which it states appears to be the Commission's intent.[498]

497. FirstEnergy proposes that a definition of franchised service territory be added to the regulations to clarify that the affiliate sales restriction would only apply to transactions involving public utilities with captive retail customers, and would not apply in areas in which there is retail choice.[499]

Commission Determination

498. The Commission's intent was that the affiliate sales restriction in proposed § 35.39(a) (now § 35.39(b)) would apply where a utility with a franchised service territory with captive customers proposes to make wholesale sales at market-based rates to a market-regulated power sales affiliate, or vice versa. Accordingly, we will revise § 35.39(a) (now § 35.39(b)) to replace ''public utility Seller with a franchised service territory'' with ''franchised public utility with captive customers.'' In light of this clarification, we do not believe it necessary to add a definition of franchised service territory to the regulations, as proposed by FirstEnergy.

[497] NOPR at P 108.

[498] Constellation at 13–17.

[499] *See*, *e.g.*, FirstEnergy at 12–13.

e. Treating Merging Companies as Affiliates

Commission Proposal

499. In the NOPR, the Commission noted that, for purposes of affiliate abuse, companies proposing to merge are considered affiliates under their market-based rate tariffs while their proposed merger is pending, and sought comments regarding at what point the Commission should consider two non-affiliates as merging partners.[500]

Comments

500. PG&E comments that affiliate sales regulations should not apply to contracts that pre-date the announcement of a merger. PG&E states that the Commission should allow merging companies sufficient time (*e.g.*, 30 days) after the announcement of a merger before enforcing the affiliate sales regulations in order to give the merging companies time to acquire the necessary information and documents to prevent a company from being held responsible for activities of the merging company that it has no knowledge of or control over.[501]

Commission Determination

501. The Commission will continue to require that, for purposes of affiliate abuse, companies proposing to merge will be treated as affiliates under their market-based rate tariffs while their proposed merger is pending.[502] The Commission will adopt the proposal to use the date a merger is announced as the triggering event for considering two non-affiliates as merging partners. In this regard, we reject PG&E's proposal that the Commission allow an additional 30 days after an announced merger to begin treating, for the purpose of affiliate abuse, merging partners as affiliates. With the extensive discussions, negotiations and review that precede the formal announcement of plans to merge, there is sufficient time for companies to acquire the necessary information and documents related to the proposed merger, particularly given that utilities are on notice of our policy in this regard.

502. The Commission clarifies that the requirement that merging companies

[500] NOPR at P 116.

[501] PG&E at 14–21.

[502] *Cinergy, Inc.*, 74 FERC ¶ 61,281 (1996); *Consolidated Edison Energy, Inc.*, 83 FERC ¶ 61,236 at 62,034 (1998); *Central and South West Services, Inc.*, 82 FERC ¶ 61,101 at 61,103 (1998); *Delmarva Power & Light Company*, 76 FERC ¶ 61,331 at 62,582 (1996) (''[T]he self-interest of two merger partners converge sufficiently, even before they complete the merger, to compromise the market discipline inherent in arm's-length bargaining that serves as the primary protection against reciprocal dealing.'').

be treated as affiliates while the proposed merger is pending only applies prospectively from the date the merger is announced and does not apply to any contracts entered into that pre-date the announcement of the merger.[503] However, in the case of an umbrella agreement that pre-dates the announcement of the merger, any transactions under such umbrella agreement that are entered into on or after the date the merger is announced would be subject to the affiliate restrictions. Further, if an announced merger does not go forward, the affiliate restrictions will cease to apply as of the date the announcement is made that the merger will not go forward.

f. Treating Energy/Asset Managers as Affiliates

Commission Proposal

503. In the NOPR, the Commission proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility with captive customers be bound by the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliates.[504] The Commission recognized that there has been an increased range of activities engaged in by asset or energy managers.[505] The Commission noted that although asset managers can provide valuable services and benefit consumers and the marketplace, such relationships also could result in transactions harmful to captive customers.[506] Accordingly, the Commission proposed that an entity managing generation for the franchised public utility should be subject to the same affiliate restrictions as the franchised public utility (*e.g.*, restrictions on affiliate sales and information sharing). The Commission referenced a settlement in which Enforcement staff alleged that an affiliated power marketer acting as an asset manager for three generation-owning affiliates violated § 214 of the FPA.[507] As a result, if a company is managing generation assets for the franchised public utility, such entity would be subject to the same information sharing provision as the franchised public utility with regard to information shared with non-regulated affiliates, such as power marketers and power producers.[508] Similarly, asset managers of a non-regulated affiliate's generation assets would be subject to the same affiliate restrictions as the market-regulated power sales affiliate, including the information sharing provision.[509]

Comments

504. Morgan Stanley comments that unaffiliated asset and energy managers should not be treated as affiliates of owners of the managed portfolios and that it would be overly inclusive for the Commission to adopt a presumption of control that would treat the energy manager as a franchised utility for purposes of the affiliate abuse rules.[510] Financial Companies argue that the Commission should not apply the affiliate abuse restrictions generically to all unaffiliated energy managers that provide management services to a franchised utility or its affiliates. Rather, the Commission should evaluate applicability of the affiliate abuse restrictions on a case-by-case basis.[511]

505. Allegheny claims that the Commission failed to consider the costs to customers, which are likely to be substantial through the loss of efficiencies by treating asset managers as affiliates.[512] Allegheny claims that there will be higher costs because: (1) The affiliated asset manager will need to pass added costs on to the franchised utility; (2) if the affiliated asset manager cannot pass on costs, it may no longer provide the service and the utility may need to set up duplicative asset management capability, resulting in higher costs; or (3) the franchised utility will need to hire a third-party asset manager, presumably more expensive.[513] Constellation makes a similar argument about the substantial costs and reduction of efficiencies by discouraging energy/asset management agreements.[514]

506. EPSA states that it opposes the Commission's proposal to treat asset managers as affiliates. It submits that asset managers are not legally affiliates of the companies with which they have a contract. If the basis for the proposal to treat asset managers as affiliates is for transparency purposes, EPSA says that all such contracts and transactions with asset managers are already reportable under the change in status final rule.[515]

507. Alliance Power Marketing argues that by imposing affiliate abuse restrictions on entities acting on behalf of a regulated public utility or its non-regulated affiliates, the Commission seeks to alter the fundamental principle of responsibility and liability of the regulated entity by making the third-party also directly accountable, thus blurring the lines of accountability. Furthermore, a critical element in applying affiliate abuse restrictions to entities' action on behalf of generation owners lies in having a stake in the outcome rather than just considering some direct or indirect control. Alliance Power Marketing asserts that evaluating control over the outcome as the threshold for asset managers could sweep up many entities, such as RTOs/ISOs, governmental and cooperative entities, that could have jurisdictional and practical ramifications.[516]

508. A number of other commenters oppose the Commission's proposal to treat unaffiliated energy/asset managers as part of the franchised public utility. They argue that the current code of conduct already provides the protections sought by such a proposal and the Commission fails to explain the need for such expanded regulation.[517] Furthermore, they submit that such proposal does not consider the additional costs to consumers through lost efficiencies.[518]

509. PG&E argues that the Commission proposal to consider ''entities acting on behalf of and for the benefit of [the utility/affiliate]'' as part of the utility/affiliate itself is unnecessary and overly broad.[519]

510. Indianapolis P&L does not oppose the Commission's proposal to treat asset managers as affiliates for the limited purposes of the code of conduct, standards of conduct or inter-affiliate transaction issues, but it states that the Commission should not treat unaffiliated asset managers as affiliates when determining how much generating

[503] This is consistent with the standards of conduct, which require transmission providers to post information concerning potential merger partners as affiliates within seven days after the potential merger is announced. 18 CFR 358.4(b)(3)(v).

[504] NOPR at P 117, 130, 131.

[505] *Id.* at P 124 citing Kevin Heslin, A few thoughts on the industry: Ideas from session at Globalcon, Energy User News, July 1, 2002, at 12 (Noting that prior to deregulation, ''an energy manager had relatively straightforward tasks: Understanding applicable tariffs, evaluating the possible installation of energy conservation measures (ECMs), and considering whether to install on-site generation'' but that ''now, an energy manager has to be conversant with a far greater number of issues'' such as complex legal issues and financial instruments like derivatives.)

[506] *Id.*

[507] *Id.* at P 124 (citing *Cleco Corp.,* 104 FERC 61,125 (2003) *(Cleco)).*

[508] NOPR at P 130.

[509] *Id.* at P 131.

[510] Morgan Stanley at 9.

[511] Financial Companies at 11–12.

[512] Allegheny at 14–15.

[513] Allegheny at 15.

[514] Constellation at 6.

[515] EPSA at 28–32.

[516] Alliance Power Marketing at 17–37.

[517] Allegheny Energy Companies at 10–16; PG&E at 14–21.

[518] Allegheny Energy Companies at 10–16.

[519] PG&E at 14–21.

capacity should be attributed to a generation asset owner.[520]

511. Financial Companies and Morgan Stanley both state in their reply comments that the Commission should not impose affiliate restrictions on unaffiliated energy managers, as the Commission provides no basis for such requirement[521] and no evidence that energy managers can engage in cross-subsidization of unregulated affiliates.[522]

Commission Determination

512. From the various comments submitted it is apparent that our proposal has created confusion as to our intent with regard to the treatment of energy/asset managers under the proposed affiliate restrictions. Accordingly, we clarify and simplify our approach, as discussed below.

513. The Commission is concerned that there exists the potential for a franchised public utility with captive customers to interact with a market-regulated power sales affiliate in ways that transfer benefits to the affiliate and its stockholders to the detriment of the captive customers. Therefore, the Commission has adopted certain affiliate restrictions to protect the captive customers and, in this Final Rule, is codifying those restrictions in our regulations. To that end, we make clear that such utilities may not use anyone, including energy/asset managers, to circumvent the affiliate restrictions (*e.g.*, independent functioning and information sharing prohibitions). Accordingly, we adopt and codify in our regulations at § 35.39(c)(1) and 35.39(g) an explicit prohibition on using third-party entities to circumvent otherwise applicable affiliate restrictions.

514. We note that energy/asset managers provide a variety of services for franchised public utilities and market-regulated power sales affiliates, including, but not limited to, operating generation plants (sometimes under tolling agreements), acting as billing agents, bundling transmission and power for customers, and scheduling transactions. However, regardless of the relationships and duties of an energy/asset manager to a franchised public utility or its non-regulated affiliate, the energy/asset manager may not act as a conduit to circumvent the affiliate restrictions.[523]

515. This approach is consistent with past Commission orders that have identified the potential that affiliated exempt wholesale generators or qualifying facilities could serve as a conduit for providing below-cost services to an affiliated power marketer at the expense of captive customers of the public utility operating companies and imposed restrictions to prevent this.[524]

516. Although several commenters assert that the costs of asset management will increase as a result of requiring asset managers to observe the affiliate restrictions, they did not provide any examples of why the costs would increase. The Commission notes that under this Final Rule, all asset managers are not required to observe the affiliate restrictions, only those asset managers which control or market generation of the franchised public utility with captive customers or a market-regulated power sales affiliate of a franchised public utility with captive customers. In those instances, the need to protect captive customers outweighs any generalized assertions of increased cost.

517. We note that to the extent that a franchised public utility with captive customers and one or more of its non-regulated marketing affiliates obtains the services of the same energy/asset manager, such an arrangement would create opportunities to harm captive customers depending on how the energy/asset manager is structured. For example, without internal separation between the energy/asset managers' regulated and non-regulated businesses, there would exist opportunities to harm captive customers.

g. Cooperatives

Comments

518. Suez/Chevron asks the Commission to clarify that jurisdictional utilities organized as cooperatives are not exempt from the affiliate abuse rules and that all jurisdictional public utilities with captive customers, including utilities organized as cooperatives, must comply with the affiliate abuse rules.[525]

519. El Paso E&P argues that it would appear that the proposed affiliate restrictions would apply to power sales at market-based rates made by G&T cooperatives to their State-regulated member distribution cooperatives. It states that based on the definition of a ''franchised public utility'' as ''a public utility with a franchised service obligation under State law and that has captive customers,'' distribution cooperatives that are granted franchised service territories by State regulatory agencies would be included in this definition. El Paso E&P asserts that a G&T cooperative with authority to sell power at market-based rates would be defined as a non-regulated power seller and, accordingly, sales made by a G&T cooperative at market-based rates to its affiliated member distribution cooperatives would, under the proposed regulations, be required to comply with the requirements of the rule.[526]

520. However, El Paso E&P argues that the Commission has previously stated that affiliate abuse is not a concern for cooperatives owned by other cooperatives because the cooperatives' ratepayers are its members. El Paso E&P alleges that the Commission has never sufficiently explained the basis for its prior statements. According to El Paso E&P, the Commission's prior statements are based on the findings in *Hinson Power*[527] that lack of concern with the potential for affiliate abuse is premised on the absence of captive customers that would be subject to the exercise of market power. El Paso submits that the fact that ratepayers of the distribution cooperative are also members of such cooperatives should not alleviate the Commission's concern about potential affiliate abuse issues. El Paso E&P claims that industrial customers of distribution cooperatives with franchised service territories are captive to service from the generation and transmission and distribution cooperatives that serve them and are in need of protection from the Commission to ensure that they are charged just and reasonable rates.[528]

521. NRECA submits that El Paso misreads the proposed regulations by classifying distribution cooperatives as a ''public utility Seller'' under the proposed regulations and NRECA comments that it is not aware of any distribution cooperatives that would be classified as ''public utility Sellers'' thus triggering the restriction on affiliate sales without first receiving Commission approval. NRECA states that nearly all distribution cooperatives are not regulated as public utilities under the FPA because they either have Rural Electrification Act (REA) financing or sell less than 4 million

[520] Indianapolis P&L at 7–10.

[521] Morgan Stanley reply comments at 14.

[522] Financial Companies reply comments at 6.

[523] The Commission is adopting 18 CFR 35.39(g) which prohibits a franchised public utility with captive customers and a market-regulated power sales affiliate from using anyone as a conduit to circumvent any of the affiliate restrictions, including the affiliate sales restriction and the information sharing provision.

[524] *Southern Company Services, Inc.,* 72 FERC ¶ 61,324 at 62,408 (1995).

[525] Suez/Chevron at 10–12.

[526] El Paso E&P at 4–9.

[527] *Hinson Power Company,* 72 FERC ¶ 61,190 (1995).

[528] El Paso E&P at 4–9.

MWh per year and thus do not qualify as a ''public utility'' under section 201(f) of the FPA. Furthermore, NRECA comments that very few distribution cooperatives sell any electricity for resale. Thus, they would not need to obtain market-based rate authority under section 205 even if they were not relieved of that obligation by section 201(f).[529] NRECA also comments that the Commission has explained the reasoning behind not requiring cooperatives to comply with the affiliate abuse requirements by stating that ''in the case of a cooperative, the cooperative's members are both the ratepayers and the shareholders, and thus there is no potential danger of shifting benefits from one to another.'' [530]

522. El Paso E&P responds that NRECA incorrectly interprets the scope of the proposed affiliate restriction and that NRECA ignores the definition of ''franchised public utility'' as ''a public utility with a franchised service obligation under State law and that has captive customers.'' El Paso E&P submits that this definition clearly includes distribution cooperatives. El Paso E&P further replies that the fact that distribution cooperatives are not ''public utilities'' regulated by the Commission is irrelevant because the Commission is not proposing to regulate sales by such distribution cooperatives. Rather, it is proposing to regulate wholesale sales by the generation and transmission cooperatives to their member distribution cooperatives. Therefore, El Paso E&P argues, the Commission should clarify the regulations to ensure that generation and transmission cooperatives are covered under the affiliate restrictions.[531]

523. El Paso E&P also responds that NRECA's attempt to divorce a generation and transmission cooperative's market-based rate sales to its distribution cooperative members from the distribution cooperative's sales to captive customers ignores the cooperative structure. It states that a generation and transmission cooperative is comprised of its member distribution cooperatives and both the generation and transmission and distribution cooperatives act in concert in connection with sales to industrial customers.[532] El Paso E&P also submits that NRECA's argument suggests that the Commission has no jurisdiction over sales to State-regulated franchised public utilities that are not cooperatives.[533] According to El Paso E&P, the captive customers of distribution cooperatives are in need of the same protection from the Commission notwithstanding that the distribution cooperatives are regulated by the states.[534]

524. El Paso E&P also states that wholesale electric sales approved by the Commission must be passed through at the retail level. Thus, El Paso E&P states that it is not sufficient to suggest that the Commission need not be concerned because the distribution cooperatives' rates are subject to State regulation.[535] Finally, El Paso E&P responds that NRECA cannot seek the protection of this Commission when its members are purchasers of power, and then claim its members should be exempt from scrutiny when they are sellers to captive customers such as El Paso E&P. It asserts that captive customers of generation and transmission and their member distribution cooperatives are in need of protection.[536]

Commission Determination

525. FPA section 201(f) specifically exempts from the Commission's regulation under Part II of the FPA, except as specifically provided, electric cooperatives that receive REA financing or sell less than 4 million megawatt hours of electricity per year.[537] Thus, such electric cooperatives are not considered public utilities under the FPA and our market-based rate regulations do not apply to those electric cooperatives. Further, with respect to distribution-only cooperatives, they either do not meet the ''public utility'' definition because they do not own or operate facilities used for wholesale sales or transmission in interstate commerce or, if they do own or operate such facilities, they are exempted from Part II regulation by virtue of FPA section 201(f). In this regard, we note that NRECA states that it is unaware of any distribution cooperatives in the United States that would be ''public utility Sellers'' under the proposed regulations.[538] Such a cooperative would not be subject to the affiliate restrictions in the proposed regulations at § 35.39.

526. For electric cooperatives that are public utility sellers and not exempted from public utility regulation by FPA section 201(f), as discussed above, the Commission will continue to treat such electric cooperatives as not subject to the Commission's affiliate abuse restrictions, based on a finding that transactions of an electric cooperative with its members do not present dangers of affiliate abuse through self-dealing. Even if an electric cooperative is not statutorily exempted from our regulation under Part II of the FPA, we conclude that a waiver of § 35.39 is appropriate. As the Commission has previously explained, ''affiliate abuse takes place when the affiliated public utility and the affiliated power marketer transact in ways that result in a transfer of benefits from the affiliated public utility (and its ratepayers) to the affiliated power marketer (and its shareholders).'' [539] However, as the Commission has previously stated in many market-based rate orders over the years,[540] where a cooperative is involved, the cooperative's members are both the ratepayers and the shareholders. Any profits earned by the cooperative will enure to the benefit of the cooperative's ratepayers. Therefore, we have found that there is no potential danger of shifting benefits from the ratepayers to the shareholders.[541]

527. Finally, we agree with NRECA's argument that the issue that El Paso E&P discusses in its comments is not a concern that can be addressed through affiliate restrictions in market-based rates, but is rather more of a concern of discrimination in the allocation of benefits and burdens among retail ratepayers. The Commission does not possess jurisdiction to review a distribution cooperative's retail rates; that issue falls under State law. Moreover, El Paso E&P's argument that wholesale electric sales approved by the Commission must be passed through at the retail level is misplaced. As the courts have previously held, State commissions are not precluded from reviewing the prudence of a company's purchasing decisions, and may disallow pass-through of wholesale purchase costs unless the purchaser had no legal right to refuse to make a particular purchase.[542]

[529] NRECA supplemental reply comments at 5–6.

[530] NRECA supplemental reply comments at 9.

[531] El Paso E&P answer to reply comments at 2–3.

[532] *Id.* at 3.

[533] *Id.*

[534] *Id.* at 4.

[535] *Id.*

[536] *Id.* at 5.

[537] 16 U.S.C. 824(e)–(f) (2006).

[538] NRECA reply comments at 5.

[539] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,062 (1994).

[540] *Hinson Power Company,* 72 FERC ¶ 61,190 (1995). *See also, e.g., People's Electric Corp.,* 84 FERC ¶ 61,215 at 62,042 (1998) (application raised no issues of affiliate abuse because the seller was operated by a cooperative whose ratepayers were also its owners); *Old Dominion Electric Cooperative,* 81 FERC ¶ 61,044 at 61,236 (1997).

[541] *Old Dominion Electric Cooperative,* 81 FERC ¶ 61,044 at 61,236 (1997).

[542] *Arkansas Power & Light Co.* v. *Missouri Public Service Commission,* 829 F.2d 1444 at 1451–52 (8th Cir. 1987). *See also Pike County Light & Power* v.

528. Therefore, for the reasons stated above, the Commission will continue to follow its current precedent and find that electric cooperatives that are public utility sellers and not exempted from public utility regulation by FPA § 201(f) are not subject to the Commission's affiliate abuse requirements.

2. Power Sales Restrictions

Commission Proposal

529. In the NOPR the Commission proposed to continue the policy of reviewing power sales transactions between regulated and ''non-regulated'' affiliates under section 205 of the FPA. This policy means, among other things, that a general grant of market-based rate authority does not apply to affiliate sales between a regulated and a non-regulated affiliate, absent express authorization by the Commission.

530. The Commission proposed to amend the regulations to include a provision expressly prohibiting power sales between a franchised public utility [543] and any of its non-regulated power sales affiliates without first receiving authorization for the transaction under section 205 of the FPA.

531. Additionally, although it did not propose to codify the requirement in the regulatory text, the Commission proposed that sellers seeking authorization to engage in affiliate transactions will continue to be obligated to provide evidence as to whether there are captive customers that would trigger the application of the affiliate restrictions. The Commission stated that if the Commission finds, based on the evidence provided by the seller, that the seller has no captive customers, the affiliate restrictions in the regulations would not apply.

532. The Commission proposed to continue its prior approach for determining what types of affiliate sales transactions are permissible and the criteria that should be used to make those decisions, including evaluation of the *Allegheny* and *Edgar* criteria.[544] Although it did not propose to codify a safe harbor provision in the regulations, the Commission noted that when affiliates participate in a competitive solicitation process, application of the *Allegheny* criteria would constitute a safe harbor that affiliate abuse conditions are satisfied in a transaction between a franchised public utility and its affiliates. The Commission emphasized, however, that using a competitive solicitation is not the only way to address concerns that an affiliate transaction does not pose undue preference concerns.[545]

533. The Commission said it continues to believe that tying the price of an affiliate transaction to an established, relevant market price or index such as in an RTO or ISO is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs. The Commission proposed to allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order [546] for eligibility for use in jurisdictional tariffs. The Commission sought comment on whether evidence other than competitive solicitations, RTO price or non-RTO price indices, or benchmarks described in the NOPR should be accepted in an application for authority to engage in market-based affiliate power sales. In addition, the Commission proposed to consider two merging partners as affiliates as of the date a merger is announced, and sought comments on this proposal (or whether to use the date the § 203 application is filed with the Commission, or another time). The Commission also proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility or non-regulated utility be bound to comply with the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliate.

534. The Commission said it continues to believe that tying the price of an affiliate transaction to an established, relevant market price or index such as in an RTO or ISO is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs. The Commission proposed to allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order [547] for eligibility for use in jurisdictional tariffs. The Commission sought comment on whether evidence other than competitive solicitations, RTO price or non-RTO price indices, or benchmarks described in the NOPR should be accepted in an application for authority to engage in market-based affiliate power sales. In addition, the Commission proposed to consider two merging partners as affiliates as of the date a merger is announced, and sought comments on this proposal (or whether to use the date the § 203 application is filed with the Commission, or another time). The Commission also proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility or non-regulated utility be bound to comply with the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliate.

Comments

535. Industrial Customers urge the Commission to recognize that when an affiliate transaction has been subject to a State-approved process, separate section 205 approvals for such transactions should not be required. If, however, the Commission does maintain the section 205 approval, ''the imprimatur of State commission approval should create a rebuttable presumption that the transaction is just and reasonable.'' [548] NASUCA comments that the Commission should not assume the reasonableness of all affiliate sales under contracts with

Pennsylvania Public Utility Commission, 465 A.2d 735 at 737–78 (1983); *Nantahala Power & Light Co.* v. *Thornburg,* 476 U.S. 953 at 965–67 (1986); *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore,* 487 U.S. 354 at 369 (1988).

[543] As proposed in the NOPR, the term ''franchised public utility'' was defined as ''a public utility with a franchised service obligation under state law and that has captive customers.'' As set forth below, to avoid confusion between references to a franchised public utility with captive customers and one without, we revise the proposed regulations to delete the reference to customers in the definition and to specifically use the term ''franchised public utility with captive customers'' to clarify when the affiliate restrictions apply.

[544] *Boston Edison Company Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) (*Edgar*), describing three types of evidence that can be used to show that an affiliate power sales transaction is above suspicion ensuring that the market is not distorted and captive ratepayers are protected: (1) Evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices non-affiliated buyers were willing to pay for similar services from the affiliate; or (3) benchmark evidence that shows the prices, terms, and conditions of sales made by non-affiliated sellers. *Allegheny Energy Supply Company, LLC,* 108 FERC ¶ 61,082 (2004) (*Allegheny*), stating four guidelines that help the Commission determine if a competitive solicitation process satisfies the *Edgar* criteria: (1) It is transparent; (2) products are well defined; (3) bids are evaluated comparably with no advantage to affiliates; and (4) it is designed and evaluated by an independent entity.

[545] Although our focus and discussion in this rule is affiliate abuse with respect to affiliates that sell at market-based rates, affiliate concerns also arise with respect to affiliate sales at cost-based rates. See, *e.g.*, *Duke Energy Corp. and Cinergy Corp.*, 113 FERC ¶ 61,297 at P 113–116 (2005), *reh'g denied*, 118 FERC ¶ 61,077 (2007).

[546] *Order Regarding Future Monitoring of Voluntary Price Formation, Use of Price Indices In Jurisdictional Tariffs, and Closing Certain Tariff Dockets*, 109 FERC ¶ 61,184 (2004) (November 19 Price Index Order).

[547] *Id.*

[548] Industrial Customers at 16–18.

prices linked to spot markets or other auction results.[549]

536. Other commenters urge the Commission to clarify that, while requests for proposals consistent with the *Allegheny* and *Edgar* standards and affiliate sales based on market index prices constitute a safe harbor for affiliate abuse, those should not be the only safe harbors.[550] The Commission should state it is willing to consider other information and evidence, including affiliate sales reviewed and authorized by a State regulatory agency, as safe harbors as well.[551]

537. New Jersey Board disagrees with comments that the Commission should consider State approval of affiliate sales as a safe harbor and responds that the Commission should assure that affiliate abuse does not take place and not ignore affiliate sales based on actions and oversight by State commissions.[552]

538. State AGs and Advocates oppose the Commission's proposal to find affiliate sales of wholesale power just and reasonable if such sales are made through an auction that reflects certain guidelines such as those set forth in Edgar and Allegheny. Instead, State AGs and Consumer Advocates state that the Commission should develop behavioral market power tests that apply to all market structures and that each auction should be assessed separately and evaluated on the merits of the proposal.[553]

539. Industrial Customers oppose the Commission's proposal to rely on an RTO/ISO benchmark price or index to mitigate affiliate abuse concerns and argues that tying an affiliate transaction to a price index should not allow utilities to escape scrutiny.[554]

Commission Determination

540. The Commission adopts the proposal to continue its approach for determining what types of affiliate transactions are permissible and the criteria used to make those decisions. Although we are not codifying a safe harbor in our regulations, when affiliates participate in a competitive solicitation process for power sales, we will consider proper application of the *Allegheny* guidelines to constitute a safe harbor that the affiliate abuse concerns are satisfied in a transaction between a franchised public utility with captive customers and its non-regulated power sales affiliate. The Commission will consider proposed competitive solicitations on a case-by-case basis. We again emphasize that using a competitive solicitation by applying the *Allegheny* and *Edgar* guidelines is not the only way an affiliate transaction can address our concerns that the transaction does not pose undue preference concerns. We will consider other approaches on a case-by-case basis. Also, to the extent a seller is not bound by the affiliate restrictions because neither the seller nor the buyer has captive customers, we find that the *Edgar* principles do not apply and the seller does not need to make a filing with regard to a proposed competitive solicitation.[555]

541. A number of commenters urge the Commission to find that a State-approved solicitation process creates a rebuttable presumption that an affiliate transaction satisfies the Commission's affiliate abuse concerns. The Commission will consider a State-approved process as evidence in its consideration as to whether our affiliate abuse concerns have been adequately addressed, but the Commission will not treat a State-approved process as creating a rebuttable presumption that our affiliate abuse concerns have been addressed. In this regard, the Commission has a responsibility under section 205 of the FPA to ensure that all jurisdictional rates charged are just and reasonable and not unduly discriminatory or preferential. While a State-approved solicitation process may provide evidence that the wholesale rates proposed as a result of that process are just and reasonable and do not involve any undue discrimination or preference, we do not believe it is appropriate to create a rebuttable presumption.

542. Further, the Commission will continue to allow an established, relevant market price or index such as in an RTO or ISO to be used as a benchmark for the reasonableness of the price of an affiliate transaction. In this regard, we disagree with commenters that relying on such prices or indices allows utilities to escape Commission scrutiny. Such an index is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs (*i.e.*, is a relevant index).[556] The Commission previously stated that the added protections in structured markets with central commitment and dispatch and market monitoring and mitigation (such as RTOs/ISOs) generally result in a market where prices are transparent.[557]

543. In addition, while the Commission has found in the past that certain non-RTO price indices are acceptable indicators of market prices, we continue to recognize that price indices at thinly traded points can be subject to manipulation and are otherwise not good measures of market prices as discussed in the Price Index Policy Statement[558] and November 19 Price Index Order. Therefore, the Commission will allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order for eligibility for use in jurisdictional tariffs and reflects the market price where the affiliate transaction occurs (*i.e.*, is a relevant index).[559]

3. Market-Based Rate Affiliate Restrictions (Formerly Code of Conduct) for Affiliate Transactions Involving Power Sales and Brokering, Non-Power Goods and Services and Information Sharing

Commission Proposal

544. The Commission stated in the NOPR that it continues to believe that a code of conduct is necessary to protect captive customers from the potential for affiliate abuse. In light of the repeal of the Public Utility Holding Company Act of 1935[560] and the fact that holding company systems may have franchised public utility members with captive customers as well as numerous non-regulated power sales affiliates that engage in non-power goods and services transactions with each other, the Commission stated that it is important to have in place restrictions that preclude transferring captive customer benefits to stockholders through a company's non-regulated power sales business. Therefore, the Commission stated its belief that it is appropriate to condition all market-based rate authorizations, including authorizations

[549] NASUCA at 20–29.

[550] Indianapolis P&L at 7–10.

[551] FirstEnergy at 12–27.

[552] New Jersey Board reply comments at 6.

[553] State AGs and Advocates reply comments at 12–13.

[554] Industrial Customers at 16–18.

[555] *Southern California Edison Co.*, 109 FERC ¶ 61,086 at P 35 (2004) (noting that Commission's concern in cases involving sales to affiliates has been the potential for cross-subsidization at the expense of the public utility's captive customers).

[556] *Brownsville*, 111 FERC ¶ 61,398 at P 10 (2005). *See also Portland General Elec. Co.*, 96 FERC ¶ 61,093 at 61,378 (2001); *FirstEnergy Trading*, 88 FERC ¶ 61,067 at 61,156 (1999).

[557] April 14 Order, 107 FERC ¶ 61,018 at P 189.

[558] *Policy Statement on Natural Gas and Electric Price Indices*, 104 FERC ¶ 61,121 (2003) (Price Index Policy Statement).

[559] *November 19 Price Index Order*, 109 FERC ¶ 61,184 at P 40–69.

[560] *Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005*, Order No. 667, 70 FR 75592 (Dec. 20, 2005), FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,197 (2005).

for sellers within holding companies, on the seller abiding by a code of conduct for sales of non-power goods and services and services between power sales affiliates. In addition, the Commission stated that greater uniformity and consistency in the codes of conduct is appropriate and, therefore, proposed to adopt a uniform code of conduct to govern the relationship between franchised public utilities with captive customers and their ''non-regulated'' affiliates, *i.e.*, affiliates whose power sales are not regulated on a cost basis under the FPA. The Commission proposed to codify such affiliate restrictions in the regulations and to require that, as a condition of receiving market-based rate authority, franchised public utility sellers with captive customers comply with these restrictions. The Commission proposed that the failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation.

545. The Commission sought comments on this proposal and on whether the specific affiliate restrictions proposed in the NOPR are sufficient to protect captive customers. In particular, the Commission sought comments on what changes, if any, should be adopted.

a. Uniform Code of Conduct/Affiliate Restrictions—Generally

Comments

546. Some commenters support codifying the code of conduct affiliate restrictions in the regulations and comment that it will lead to consistent codes of conduct across all sellers, thus creating greater transparency, and will aid the Commission's enforcement efforts.[561] ELCON argues that the ability of large utility holding companies with one foot in ''competition'' and one foot in ''regulation'' creates a myriad of potential problems.[562] Several State agencies and consumer commenters generally support the proposal to codify uniform code of conduct restrictions in the Commission's regulations.[563] NASUCA comments that the separation of function requirements should apply to any affiliate with retail customers, not just to affiliates who are franchised public utilities.[564]

547. FP&L, however, does not believe it is unduly preferential to have different codes of conduct.[565] Indianapolis P&L argues that a single tariff/code of conduct does not make sense for diversified energy companies with geographically widespread operations.[566]

548. FP&L states that the Commission should include in the regulatory text the statement that the affiliate restrictions are waived where a seller demonstrates that there are no captive customers.[567] EEI states that utilities already found not to have captive customers because of retail choice should be grandfathered and should not have to request waiver of the code of conduct again.[568]

Commission Determination

549. The Commission will adopt the proposed affiliate restrictions with certain modifications and clarifications. These restrictions govern the separation of functions, the sharing of market information, sales of non-power goods or services, and power brokering. The Commission will require that, as a condition of receiving and retaining market-based rate authority, sellers comply with these affiliate restrictions unless otherwise permitted by Commission rule or order. As discussed herein, these affiliate restrictions govern the relationship between franchised public utilities with captive customers and their ''market-regulated'' affiliates, *i.e.*, affiliates whose power sales are regulated in whole or in part on a market-based rate basis.

550. Failure to satisfy the conditions set forth in the affiliate restrictions will constitute a violation of the market-based rate tariff. As discussed in greater detail below, the Commission agrees with many of the commenters that the requirements and exceptions in the affiliate restrictions should follow those requirements and exceptions codified in the standards of conduct, where applicable.[569] The Commission believes that modeling these restrictions and the exceptions to those restrictions on the standards of conduct will lead to greater consistency and transparency and a greater understanding of permissible activities.

551. The Commission clarifies that any sellers that have previously demonstrated and been found not to have captive customers, and therefore have received a waiver of the market-based rate code of conduct requirement in whole or in part, will not be required to request another waiver of the associated affiliate restrictions. However, those sellers are still under the obligation to report to the Commission any changes in status that may affect the basis on which the Commission relied in granting their waiver, consistent with the requirements of Order No. 652.[570] Additionally, those sellers also will be required to meet the requirements necessary to maintain their market-based rate authority when they file their regularly scheduled updated market power analyses. As a result, they will be required to demonstrate that they continue to lack captive customers in order to support a continued waiver of the affiliate restrictions in the regulations. Sellers will also need to explain why any wholesale customers are not captive, as explained above.

552. In response to FP&L and EEI, because we clarify in this Final Rule that, where a seller demonstrates and the Commission agrees that it has no captive customers, the affiliate restrictions will not apply, the Commission does not believe it is necessary to include in the regulatory text a provision stating that the affiliate restrictions are waived where a seller demonstrates and the Commission agrees that it has no captive customers.

[561] ELCON and EPSA support codifying a uniform code of conduct. ELCON at 2 and EPSA at 28.

[562] ELCON at 3.

[563] *Id.* at 6–10, New Jersey Board at 2, and NRECA at 11.

[564] NASUCA at 20–29.

[565] FP&L at 3.

[566] Indianapolis P&L at 12.

[567] FP&L at 5–6.

[568] EEI at 43; EEI reply comments at 35.

[569] On November 17, 2006, the D.C. Circuit vacated the Order No. 2004 standards of conduct orders as they related to natural gas pipelines and remanded the orders to the Commission. *National Fuel Gas Supply Corporation* v. *FERC*, 468 F.3d 831 (D.C. Cir. 2006). The court found that the rulemaking record did not support the Commission's attempt to extend the standards of conduct beyond pipelines' relationships with their marketing affiliates to also govern pipelines' relationships with numerous non-marketing affiliates, such as producers, gatherers, and local distribution companies (which Order No. 2004 defined as ''energy affiliates''). In response to this decision, the Commission issued an interim rule on January 9, 2007 reinstating those provisions of Order No. 2004 that were not specifically appealed to the D.C. Circuit. *Standards of Conduct for Transmission Providers*, Order No. 690, 72 FR 2427 (Jan. 19, 2007); FERC Stats. & Regs. ¶ 31,237 (Jan. 9, 2007); *order on reh'g, Standards of Conduct for Transmission Providers*, Order No. 690–A, 72 FR 14235 (Mar. 27, 2007); FERC Stats. & Regs. ¶ 31,243 (2007). On January 18, 2007, the Commission issued a Notice of Proposed Rulemaking proposing to make the changes in the Interim Rule permanent and seeking comment on whether the restrictions covering relationships between electric transmission providers and non-marketing affiliates that are engaged in energy transactions should be retained. *Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 72 FR 3958 (Jan. 29, 2007), FERC Stats. & Regs. ¶ 32,611 (2007).

[570] *Reporting Requirement For Changes in Status For Public Utilities with Market-Based Rate Authority*, Order No. 652, 70 FR 8253 (Feb. 18, 2005), FERC Stats. & Regs., Regulations Preambles January 2001–December 2005 ¶ 31,175, *order on reh'g*, Order No. 652–A, 111 FERC ¶ 61,413 (2005).

b. Exceptions to the Independent Functioning Requirement

Commission Proposal Regarding Separation of Employees and Shared Employees

553. In the NOPR, the Commission proposed regulatory language in § 35.39(b)(2) (now § 35.39(c)(2)) codifying the independent functioning requirement. Specifically, the Commission stated, to the maximum extent practical, the employees of a non-regulated power sales affiliate will operate separately from the employees of any affiliated franchised public utility.

554. The Commission did not propose to include any exceptions to the independent functioning requirements. However, the Commission invited commenters to propose additions to, substitutions for or elimination of the proposed affiliate restrictions.[571]

Comments

555. A number of commenters request that the Commission modify the affiliate restrictions to adopt some of the requirements and exceptions consistent with those codified in Order No. 2004, such as allowing the sharing of senior officers and members of the board of directors, field and maintenance employees and support employees. According to EPSA, the affiliate restrictions should provide specifically for permissible sharing of officers (not just sharing of support personnel) between a franchised public utility and a non-regulated power sales affiliate. EPSA notes that Order No. 2004 allows for shared officers as long as they do not direct, organize or execute day-to-day business transactions.[572]

556. Duke comments that treatment of shared employees under the affiliate restrictions should follow the obligations adopted in the standards of conduct. For example, Duke urges the Commission to allow the sharing of officers and directors.[573] Additionally, Avista states that the proposed affiliate restrictions should distinguish between operational and non-operational employees.[574]

557. PG&E urges the Commission to clarify which employees cannot be shared. PG&E states that prohibiting employees involved in general operation of generation facilities, who lack control over generation availability, from being shared would be overly broad and unduly restrictive.[575] PPL similarly requests clarification of which employees would be deemed ''shared employees'' under the affiliate restrictions.[576]

558. NiSource requests that the Commission create an exception to allow the sharing between operational employees of the franchised public utility and its non-regulated sales affiliates of any information necessary to maintain the safe and reliable operation of the bulk power system, similar to the exception in the standards of conduct at § 358.5(b)(8) of the Commission's regulations.[577]

559. EEI and FirstEnergy also request that the independent functioning requirement and information sharing restrictions in the proposed affiliate restrictions should have an exception for sharing employees and market information for emergency circumstances affecting system reliability.[578]

560. On the other hand, Morgan Stanley urges the Commission not to adopt a blanket exception to the affiliate restrictions for emergency situations because the commenters' proposal regarding what constitutes an ''emergency'' is vague and leaves too much discretion to the individual sellers. Additionally, Morgan Stanley explains that communications with an affiliate during an emergency may not adequately address an emergency; sharing information with all sellers in the market would provide a better foundation to deal with any emergency.[579]

Commission Determination

561. The Commission will revise the independent functioning requirement of the affiliate restrictions to include exceptions relating to permissibly shared senior officers and members of boards of directors, shared support personnel, and shared field and maintenance personnel. With regard to permissibly shared individuals, the Commission will impose a ''no-conduit rule'' similar to that in the standards of conduct.[580] Under the no conduit rule, to be codified at § 35.39(g), a permissibly shared employee is prohibited from acting as a conduit for disclosing market information to employees, officers or directors that are not shared.

562. The Commission agrees that a franchised public utility with captive customers and its market-regulated power sales affiliates should be permitted to share senior officers and members of the board of directors to conduct corporate governance functions, and to take advantage of the efficiencies of corporate integration.[581] Therefore, the Commission is adopting an exception at § 35.39(c)(2)(d) that permits a franchised public utility with captive customers and its market-regulated power sales affiliate to share senior officers and members of the board of directors. Specifically, a franchised public utility with captive customers and its market-regulated power sales affiliate may share senior officers and members of boards of directors provided that these individuals do not participate in directing, operating or executing generation or market functions.[582] In addition, to prevent permissibly shared senior officers or members of the board of directors from using their preferential access to market information to harm captive customers, consistent with the no-conduit rule codified at § 35.39(g), the permissibly shared senior officers and directors may not act as a conduit to provide market information to non-shared employees of the franchised public utility with captive customers or its market-regulated power sales affiliates.

563. The Commission also agrees that it is appropriate to codify an exception that permits the sharing of support employees between the franchised public utility with captive customers and its market-regulated power sales affiliates comparable to the standards of conduct exception, likewise subject to the no-conduit rule.[583]

564. The Commission rejects Duke's request that the Commission include a non-exhaustive list of examples of permissible shared support employees within the body of § 35.39. However, we clarify that the types of permissibly shared support employees under the standards of conduct are the types of permissibly shared support employees that will be allowed under the affiliate restrictions in § 35.39(c)(2)(c). Such employees include those in legal, accounting, human resources, travel and information technology.[584] Because permissibly shared employees may have access to market information, they are

[571] NOPR at P 132.

[572] EPSA at 31.

[573] Duke at 43. *See also* EPSA at 31; FirstEnergy at 26.

[574] Avista at 7–10.

[575] PG&E at 14–21.

[576] PPL reply comments at 21–22.

[577] NiSource at 1.

[578] EEI at 44; FirstEnergy at 22.

[579] Morgan Stanley reply comments at 7–8.

[580] 18 CFR 358.4(a)(5) (shared senior officers and directors); 18 CFR 358.5(b)(7) (general ''no conduit'' rule covering employees).

[581] Order No. 2004–A at P 134.

[582] *See* 18 CFR 358.4(a)(5).

[583] Order No. 2004 at P 99–101.

[584] *Id.* at P 96.

prohibited from acting as a conduit to provide market information to employees of the franchised public utility with captive customers and the market-regulated power sales affiliates that are not permitted to be shared.

565. The Commission also agrees to codify an exception to the independent functioning requirement to allow franchised public utilities with captive customers and their market-regulated power sales affiliates to share field and maintenance employees. Field and maintenance employees perform purely manual, technical or mechanical duties that are supportive in nature and do not have planning or direct operational responsibilities. Such employees would likely be part of shared work crews to do repair or maintenance work on facilities or equipment. Examples of activities that may be performed by shared field and maintenance employees are reading meters, replacing parts in generators, restringing transmission lines, snow removal or maintaining roadways. The key is that these employees do not also perform operational duties.[585] A field or maintenance employee cannot be shared if that employee also engages in marketing activities, makes decisions that would affect marketing activities, or controls generation. We also consider the immediate supervisors of field and maintenance employees as permissibly shared employees so long as they cannot control operations, *e.g.* restrict or shut down generation facilities.[586]

566. The Commission agrees with commenters that allowing the sharing of field and maintenance employees between a franchised public utility with captive customers and its market-regulated power sales affiliates is unlikely to harm captive customers, provided that those shared employees do not act as a conduit for sharing market information with employees of the franchised public utility with captive customers or market-regulated power sales affiliates. The permissibly shared field and maintenance employees are required to observe the no-conduit rule.

567. The Commission disagrees with NiSource that a broad exception to the independent functioning and information sharing requirement is needed for the reliable operation of the bulk power system. Such an exception would be so broad that it would swallow the rule and create too many opportunities for shared employees to take actions to harm captive customers based upon their decision making authority and control over the bulk power system. The Commission will consider requests for waiver of the affiliate restriction requirements to address the specific circumstances of the operation of a bulk power system and notes that, subsequent to NiSource's comments, the Commission granted a partial waiver of the code of conduct requirements for the situation described in NiSource's comments.[587]

568. While the Commission does not agree with NiSource's proposal for a broad exception to the affiliate restrictions for everyday operations of the bulk power system, the Commission does agree with EEI and FirstEnergy that the affiliate restrictions should contain an exception related to emergency circumstances affecting system reliability. As such, the Commission will adopt an exception to the independent functioning requirement and the information sharing restrictions for emergency circumstances affecting system reliability comparable to the exception in the standards of conduct.[588] The exception will apply to both the independent functioning requirements and the information sharing restrictions. The Commission will modify proposed § 35.39(d) (to be codified at § 35.39(c)(2)(b)) to add a provision that states that, notwithstanding any other restrictions in this section, in emergency circumstances affecting system reliability, a market-regulated power sales affiliate and the franchised public utility with captive customers may take the necessary steps to keep the bulk power system in operation. The relaxation of the requirements during system emergencies is intended to ensure that the franchised public utility with captive customers and market-regulated power sales affiliate(s) can maintain reliability of the power grid. However, the market-regulated power sales affiliate or the franchised public utility must report to the Commission and disclose to the public on its Web site each emergency that resulted in any deviation from the restrictions of § 35.39(c)(2)(b), within 24 hours of such deviation. Reports to the Commission of emergency deviations under the affiliate restrictions in § 35.39(c)(2)(b) will be made using the ''EY'' docket prefix.

569. The Commission and the public will be able to monitor the frequency of these emergency deviations through the reporting requirement. Members of the public can seek redress from the Commission if they feel that the exception has been abused or used improperly.

c. Information Sharing Restrictions

Commission Proposal

570. In the NOPR, the Commission proposed regulatory language to codify the information sharing restrictions. Specifically, the Commission proposed that the regulations provide that all market information sharing between a franchised public utility and a non-regulated power sales affiliate will be disclosed simultaneously to the public. This includes, but is not limited to any communication concerning power or transmission business, present or future, positive or negative, concrete or potential.[589]

Comments

571. Ameren supports codification of the information sharing restrictions, but recommends that proposed § 35.39(c) be revised to allow permissibly shared senior officers and directors to receive market information so long as they do not act as a conduit to improperly share such information, akin to the standards of conduct.

572. Avista argues that the Commission should allow officers to be shared by affiliates, subject to the no-conduit rule.[590] EEI argues that for corporate governance and accountability purposes, there should be an exception to the information sharing prohibitions for shared senior officers, subject to the no conduit rule.[591]

573. EPSA also asks the Commission to provide a specific time period for the length of time that posted information needs to remain on the Web site.[592]

574. PPL comments that the Commission should clarify which situations would permit deviations from the code of conduct regarding

[585] *Id.* at P 145–146.

[586] *See id.* at P 145–46. As discussed later, such actions would be permitted in emergency circumstance affecting system reliability.

[587] *Northern Indiana Public Service Company and Whiting Clean Energy, Inc.,* 116 FERC ¶ 61,248 (2006). Northern Indiana Public Service Company (NIPSCO) sought a waiver of the code of conduct so that it could perform its duties as a balancing authority. Specifically, NIPSCO wanted the ability to have access to real-time information regarding the amount of energy being delivered to NIPSCO from its affiliate, Whiting Clean Energy, Inc., (Whiting). The Commission granted a partial waiver limited to Whiting providing NIPSCO with the real-time information NIPSCO needed to carry out its responsibilities as a balancing authority in accordance with the requirements of the North American Electric Reliability Council (NERC), NERC approved regional reliability organization and the Midwest Independent Transmission System Operator, Inc. *Id.* at P 13. The Commission also reminded NIPSCO that its employees were prohibited from being a conduit for improperly sharing Whiting's generation information. *Id.*

[588] 18 CFR 358.4(a)(2).

[589] *See* NOPR at P 121, 129.

[590] Avista at 2.

[591] EEI at 44.

[592] EPSA at 31–32.

information sharing. Specifically, it suggests that the Commission adopt, for the affiliate restrictions, the standards of conduct exception that permits the sharing of information to comply with Nuclear Regulatory Commission (NRC) requirements.[593]

575. A number of commenters argue that the Commission should not adopt the two-way information sharing prohibition in the uniform code of conduct because they disagree that a communication from the non-regulated power sales affiliate to the franchised public utility could potentially harm captive customers.[594]

576. Duke notes that while the two-way restriction is consistent with the default code of conduct that the Commission has used since 1999, the Commission has approved many codes of conduct that contain one-way restrictions (*i.e.*, codes that restrict a franchised public utility from sharing marketing information with its non-regulated power sales affiliates, but do not place a similar restriction on a non-regulated power marketer from sharing market information with its affiliated franchised utility). Duke says the Commission has failed to explain the elimination of previously-approved one-way restrictions.[595] It submits that the one-way code of conduct is sufficient to address affiliate abuse concerns and that the two-way code of conduct requirement will impose substantial costs on market-based rate sellers with no discernible benefits.[596] According to Duke, a number of market participants have made important organizational and commercial decisions based on current policies and precedents allowing one-way communications. In the absence of any basis for reversing that policy, Duke submits that the Commission should reconsider its proposal to mandate two-way information sharing restrictions.

577. In addition, Duke argues that only two commenters, EPSA and ELCON, expressed even generalized support for a standardized code of conduct containing the two-way code restriction, but did not address the underlying policy issues of why or how a traditional utility's regulated customers could be harmed if their unregulated affiliate were to share market information with the utility.[597]

578. According to FP&L, the proposed two-way information sharing restriction does not provide any additional protection for captive customers. Rather, such a restriction may place artificial and unnecessary barriers on a company's ability to conduct business.[598] According to FP&L, the two-way restriction proposed in § 35.39(c) (to be codified at § 35.39(d)) concerning the communication of all market information between a franchised public utility and its non-regulated power sales affiliates is unnecessary if sales of capacity and energy between those entities are prohibited under the specific terms of the market-based rate tariff. It submits that, if the Commission nevertheless concludes that a two-way restriction on communications should be adopted, then the final regulations should provide an exception if, in the market-based rate tariff, the non-regulated power sales affiliates have restricted sales to, and purchases from, their franchised public utility affiliate without having received advance Commission approval pursuant to a separate filing under section 205 of the FPA.[599]

579. Similarly, EEI argues that the Commission has not explained how the two-way information sharing prohibition protects captive customers.[600]

Commission Determination

580. The Commission will revise the information sharing prohibitions to adopt certain exceptions. As discussed earlier with regard to the independent functioning requirement, we are creating exceptions to permit shared senior officers and members of a board of directors, as well as to permit shared field and maintenance employees. Permissibly shared employees may share all types of market information. However, the information sharing provision, like all the affiliate restrictions, is subject to the ''no-conduit'' rule that we codify in the regulations. The no-conduit rule allows permissibly shared employees to receive market information so long as they are not conduits for sharing that information with employees that are not permissibly shared. In addition, as also discussed earlier in the independent functioning section, market information may be shared to address emergency circumstances affecting system reliability in order to keep the bulk power system in operation, provided that the subsequent reporting provisions are followed.

581. In response to PPL Companies' concern as to communications relating to nuclear power plants, the Commission clarifies that the types of communications permitted under the standards of conduct for nuclear safety and regulatory requirements are also permitted under the affiliate restrictions.[601] Specifically, the Commission permitted transmission providers to communicate with affiliated and nonaffiliated nuclear power plants to enable the nuclear power plants to comply with the requirements of the NRC as described in the NRC's February 1, 2006 Generic Letter 2006–002, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power.[602]

582. In response to EPSA's request regarding the specific time period that posted material needs to remain on the Web site, the Commission concludes that it is appropriate to use the requirements set forth regarding OASIS postings in 18 CFR 37.7(b). Specifically, the material must be posted for 90 days and then be retained and made available upon request for download for five years from the date when first posted. The archived material must be available in the same electronic form used as when it was originally posted.

583. The Commission will adopt the two-way information sharing restriction in proposed § 35.39(c) (now § 35.39(d)). The purpose of the affiliate restrictions in § 35.39 is to ensure that franchised public utility sellers with captive customers will not be able to engage in affiliate abuse to the detriment of those captive customers. One way the Commission achieves this is by restricting the sharing of information between a franchised public utility with captive customers and a market-regulated power sales affiliate. The Commission has long required a seller

[593] PPL reply comments at 21–22 citing *Interpretive Order Relating to the Standards of Conduct,* 114 FERC ¶ 61,155 (2006), *order on request for additional clarification,* 115 FERC ¶ 61,202 (2006).

[594] Allegheny Energy Companies' Comments at 3; Duke at 37–40; PG&E at 20, FirstEnergy at 23 and FP&L at 4.

[595] Duke at 38.

[596] Duke reply comments at 20–21.

[597] *Id.* at 20.

[598] FP&L at 4.

[599] *Id.* at 4–5.

[600] EEI at 45.

[601] *Interpretive Order Relating to the Standards of Conduct,* 114 FERC ¶ 61,155 (2006), *order on request for additional clarification,* 115 FERC ¶ 61,202 (2006).

[602] Nuclear Regulatory Commission's Generic Letter 2006–002, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power. February 1, 2006. OMB Control No.: 3150–0011. Transmission providers may share with affiliates information to operate and maintain the transmission system and information required to maintain interconnected facilities. However, transmission providers may not share transmission or marketing information that would give a transmission provider's marketing or energy affiliates undue preference over a transmission provider's non-affiliated customers in energy markets. 114 FERC ¶ 61,155 (2006).

to address any potential affiliate abuse concerns before receiving Commission authorization to sell at market-based rates. The Commission has previously held that ''[t]here are many ways for the affiliated public utility and the affiliated power marketer to exchange information that would exacerbate affiliate abuse concerns.'' [603] Therefore, the Commission required that the sellers ''ensure that market information is not shared among affiliates.'' [604]

584. The Commission later reaffirmed this in stating the general standards under which it reviews applications for market-based rate authority, including a demonstration by an affiliate that ''there are adequate procedures in place to ensure that market information is not shared between it and the affiliate public utility.'' [605]

585. With regard to Duke's suggestion that we have failed to explain the elimination of the one-way restriction, we will provide the following example of our concern in this regard.

586. One example of how of improper sharing of information could harm captive customers is a circumstance where both a franchised public utility and its market-regulated power sales affiliate are considering whether to bid into an RFP to provide power. If the market-regulated power sales affiliate has absolute freedom to inform its franchised public utility affiliate that it intends to bid into the RFP, including but not limited to the price and quantity it intends to offer, the franchised public utility affiliate has the ability and incentive to use that information to benefit its stockholders at the expense of its captive customers (*e.g.*, by either not bidding into the RFP or doing so at a price above that of its affiliate).

587. While we recognize that some sellers may need to adjust their activities to comply with the two-way information restriction, we do not believe that such adjustments will impose significant costs upon those sellers. Furthermore, as explained above, we believe that the two-way information sharing restriction will provide captive customers a more complete protection from affiliate abuse. We find that any potential cost to sellers is outweighed by the increased protection a two-way information sharing restriction provides to captive customers.

588. Therefore, to ensure that all captive customers are protected from the potential for affiliate abuse, the Commission will adopt the proposed two-way information restriction in § 35.39(d). Any sellers whose activities are currently governed by a code of conduct with a one-way information restriction will be deemed to have adopted a two-way information restriction as of the effective date of this Final Rule.

589. The Commission restates that the affiliate restrictions only apply when captive customers exist; therefore, if the Commission has found that there are no captive customers, then, consistent with § 35.39(b) through (g), the affiliate restrictions, including the prohibition on information sharing, will not apply.

d. Definition of ''Market Information''

Comments

590. Progress Energy urges the Commission to clarify the definition of the term ''market information'' which it argues is arbitrarily broad and may include public as well as non-public market information.[606] SoCal Edison states that the Commission should only prohibit the sharing of non-public market information among a utility and its market-regulated power sales affiliates, as outlined in the standards of conduct.[607] EPSA also asserts that the Commission should clarify that the simultaneous posting requirement should apply to the communication of all non-public market information (not all market information). It notes that Order No. 2004 specifically applies to non-public transmission information, not all transmission information.

Commission Determination

591. The Commission previously explained that ''market information'' includes information on sales or purchases that will not be made (as well as purchases and sales that will be made), as well as any information concerning a utility's power or transmission business—broker-related or not, past, present or future, positive or negative, concrete or potential, significant or slight.[608] In an effort to provide additional clarity and regulatory certainty, we will provide further guidance and adopt and codify in § 35.36(a)(8) the following definition of market information: ''market information means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.''

592. The Commission clarifies that the definition does not prohibit the disclosure of publicly available information. We find that, because of its very nature of being publicly available to all entities, restrictions on sharing publicly available information are unnecessary. In addition, the definition does not prohibit the sharing of transmission information. The standards of conduct already prevent improper disclosures of non-public transmission information by a transmission provider to its marketing and energy affiliates, which would include both the franchised public utility with captive customers and the market-regulated power sales affiliate.[609]

593. Further, as we have indicated, a principal purpose of the affiliate restrictions is to ensure that the interaction between a franchised public utility and its market-regulated affiliate does not result in harm to the franchised public utility's captive customers. Therefore, we clarify that, as a general matter, the definition of ''market information'' includes information that, if shared between a franchised public utility and a market-regulated affiliate, may result in a detriment to the franchised public utility's captive customers. Therefore, market information includes, but is not limited to, information concerning sales and purchases that will not be made such as in circumstances where parties have discussed a potential contract but no agreement has been reached. In contrast, market information does not include information that would not result in an advantage to the recipient that could be used to the detriment of the franchised public utility's captive customers. For example, a franchised public utility with captive customers and its market-regulated power sales affiliate may share information related to the relocation of the franchised public utility's headquarters, business opportunities outside the United States, general turbine safety information and internal procedures for general maintenance activities (other than scheduling). We clarify that the definition of ''market information'' includes, but is not limited to, written, printed, verbal, audiovisual, or graphic information.

594. We are adding language to the information sharing restriction of § 35.39(d)(1) to make clear that disclosures of market information are

[603] *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994).

[604] *Id.*

[605] *LG&E Power Marketing, Inc.*, 68 FERC ¶ 61,247 (1994).

[606] Progress Energy at 36–37.

[607] SoCal Edison at 3–6.

[608] *UtiliCorp United, Inc.*, 75 FERC ¶ 61,168 (1996).

[609] 18 CFR 358.5(a) and (b) (2006).

prohibited, unless simultaneously disclosed to the public, if the information could be used to the detriment of captive customers. For example, if a franchised public utility with captive customers conducts negotiations with an unaffiliated generator to acquire power, but does not reach an agreement, the franchised public utility with captive customers is prohibited from sharing with its market-regulated power sales affiliate any non-public information it acquired through the unsuccessful negotiations unless such information is simultaneously disclosed to the public. Information relating to any other entities' electric energy or power business is also subject to the sharing of market information restriction if such information could be used to the detriment of captive customers. Also subject to the information sharing restriction is information regarding brokering activities, past sales and purchase activities, and the availability or price of inputs to generation such as natural gas supply if such information could be used to the detriment of captive customers. For example, a franchised public utility with captive customers is restricted from disclosing to its market-regulated power sales affiliate any non-public information about a non-affiliated generator's upcoming maintenance or outage schedules or information about the non-affiliated generator's historical generation volumes, unless such information is simultaneously disclosed to the public. In addition, neither the franchised public utility with captive customers nor its market-regulated power sales affiliate may tell the other that it intends to sell power to a third party, including but not limited to the price and quantity it intends to offer, unless such information is simultaneously disclosed to the public. Similarly, a market-regulated power sales affiliate is likewise restricted from telling its franchised public utility affiliate with captive customers about any other business opportunity that it is considering or is undertaking, unless such information is simultaneously disclosed to the public.

e. Sales of Non-Power Goods or Services

Commission Proposal

595. In the NOPR, the Commission proposed regulatory language to codify the requirements governing sales of non-power goods or services. The Commission proposed that sales of any non-power goods or services by a franchised public utility to a market-regulated power sales affiliates will be at the higher of cost or market price, and that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility will not be at a price above market.

Comments

596. PG&E argues that, while charging the high of cost or market price may be appropriate for sales of goods, it is ''inoperable and inappropriate'' for sales of services because market prices for sales of service by a third party may be hard to ascertain due to limited providers and that prices from a third party provider will not take into account efficiencies resulting from a utility and its affiliate sharing services.[610] PG&E further comments that charging the higher of cost or market, as proposed, may increase costs for both the utility and the affiliate by discouraging the efficient sharing of services. Therefore, PG&E proposes that instead of charging the higher of cost or market price for non-power services, the Commission should allow a proxy for the market price such as the fully-loaded cost plus a reasonable profit, *e.g.*, five percent.[611]

Commission Determination

597. The Commission will adopt the NOPR proposal to codify the requirement that sales of non-power goods and services by a franchised public utility with captive customers to a market-regulated power sales affiliate be at the higher of cost or market price, unless otherwise authorized by the Commission. This requirement, along with other requirements in the affiliate restrictions, protect a franchised public utility's captive customers against inappropriate cross-subsidization of market-regulated power sales affiliates by ensuring that the utility with captive customers does not recover too little for goods and services that the utility provides to a market-regulated power sales affiliate.[612] We also adopt the NOPR proposal to codify the requirement that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers will not be at a price above market, unless otherwise authorized by the Commission. This requirement protects a utility's captive customers against inappropriate cross-subsidization of market-regulated power sales affiliates by ensuring that the utility with captive customers does not pay too much for goods and services that the utility receives from a market-regulated power sales affiliate.

598. We note that PG&E fails to provide the Commission with any specific examples of non-power services for which there is no corresponding third-party provider. Therefore, we are not persuaded by PG&E that there is a need or a benefit to changing our precedent on this issue. We will adopt the affiliate restrictions as proposed and require that sales of non-power goods or services by a franchised public utility with captive customers to a market-regulated power sales affiliate be at the higher of cost or market price. Nevertheless, we will address on a case-by-case basis arguments that charging the higher of cost or market for certain sales of non-power services may not be appropriate in a particular case.

f. Service Companies or Parent Companies Acting on Behalf of and for the Benefit of a Franchised Public Utility

Commission Proposal

599. The Commission proposed in the NOPR to treat companies that are acting on behalf of and for the benefit of franchised public utilities with captive customers, for purposes of the affiliate provisions, as that franchised public utility. Likewise, in the case of non-regulated affiliates, the proposed affiliate provisions treat companies that are acting on behalf of and for the benefit of non-regulated affiliates, for purposes of the affiliate provisions, as the non-regulated affiliates.[613]

Comments

600. EEI asks the Commission to clarify that the code of conduct (affiliate restrictions) provisions to be codified in the regulations do not preclude the use of service companies that manage assets for both regulated and unregulated affiliates.[614] EEI submits that the language of proposed § 35.39(b) (now § 35.39(c)) uses ''entities acting on behalf of and for the benefit of a franchised pubic utility (such as entities managing the electric generation assets of the franchised public utility)'' whereas the NOPR text reads ''entities acting on behalf of and for the benefit of a franchised public utility (such as service companies and entities managing the generation assets of the franchised pubic utility).'' EEI argues that the treatment of service companies as part of the franchised public utility in the preamble to the NOPR is different from the language in the proposed

[610] PG&E at 20–21.

[611] *Id.* at 21.

[612] *See generally National Grid plc and Keyspan Corp.*, 117 FERC ¶ 61,080 at P 65–66 (2006), *reh'g pending.*

[613] NOPR at 83–84.

[614] EEI at 45–46.

regulation and makes the Commission's intent unclear. It submits that many companies use service companies to provide support activities to the franchised utility and non-regulated affiliates consistent with the no-conduit rule. EEI asks the Commission to clarify that the standardization of the code of conduct is not intended to change this practice. PG&E claims that under a plain reading of the proposed regulation, a parent company that acts on behalf of either the utility or the affiliate will be considered a part of the utility or affiliate, and communication with either entity will be restricted under proposed § 35.39(c) (now § 35.39(d)).[615] It argues that the Commission should only consider a holding company or parent company as an affiliate subject to the information sharing prohibitions if it engages in energy transactions on its own behalf.[616]

601. Southern states that it is unclear how the Commission intends to address and apply the requirements of separation of functions and information sharing in the context of public utility holding companies that have system pooling agreements.[617] Southern recommends the Commission refine the definition of ''non-regulated power sales affiliate'' at least insofar as that term is used in the proposed separation of functions and information sharing provisions to exclude pooled system affiliates of traditional franchised utilities where affiliate interactions and sharing of benefits and burdens of pooled operations are addressed under an arrangement filed and approved under section 205.[618]

602. EEI requests that the Commission clarify that, in circumstances where sales between affiliates have been made in connection with an approved system agreement, such agreements continue to govern.[619] Southern requests that the Final Rule clarify that affiliated operating companies may continue to operate on a pooled basis.[620] Southern states that traditional centralized service company affiliates providing system pooling support services under filed and approved system agreements should not be treated as non-regulated power sales affiliates.[621]

Commission Determination

603. The Commission clarifies that it did not intend to include service companies as ''entities acting on behalf of and for the benefit of a franchised public utility'' for purposes of the separation of functions provision in § 35.39(b) (now § 35.39(c)) to the extent that such service companies do not engage in generation or marketing activities.[622] Although service companies not engaged in generation or marketing activities are not included in the coverage of § 35.39(e), they may not act as a conduit for providing non-public market information between a franchised public utility and a market-regulated power sales affiliate. However, unless otherwise permitted by Commission rule or order, service companies cannot be used to direct, organize or execute generation or marketing activities for both the franchised public utility and the market-regulated power sales affiliate(s). In response to Southern's and EEI's request to clarify that affiliated operating companies may continue to operate as a pool or pursuant to an approved system agreement, nothing in this Final Rule precludes pool operation pursuant to filed tariffs or agreements approved by the Commission and nothing in this rule changes filed system agreements approved by the Commission. To the extent that individual companies enter into new pooling or system agreements, the Commission will continue to review those agreements on a case-by-case basis to ensure that, among other things, affiliate transactions meet the requirements of section 205 of the FPA and otherwise satisfy our affiliate abuse concerns.

D. Mitigation

604. In the NOPR, the Commission sought comment on whether the default mitigation adopted in the April 14 Order is appropriate as currently structured. The Commission's current default mitigation rates are as follows: (1) Sales of power of one week or less will be priced at the seller's incremental cost plus a 10 percent adder; (2) sales of power of more than one week but less than one year (sometimes referred to as ''mid-term sales'') will be priced at an embedded cost ''up to'' rate reflecting the costs of the unit or units expected to provide the service; and (3) new contracts for sales of power for one year or more will be priced at a rate not to exceed the embedded cost of service, and the contract will be filed with the Commission for review and approved prior to the commencement of service.[623]

605. In the NOPR, the Commission sought comment on the following four issues that have arisen in implementing cost-based mitigation: (i) The rate methodology for designing cost-based mitigation; (ii) discounting; (iii) protecting customers in mitigated markets; and (iv) sales by mitigated sellers that ''sink'' in unmitigated markets.

1. Cost-Based Rate Methodology

a. Sales of One Week or Less

Commission Proposal

606. The Commission noted that two principal issues concerning rate methodology have arisen in implementing the April 14 Order. The first relates to power sales of one week or less being made at incremental cost plus 10 percent.[624] The Commission noted that sellers have argued that this is a departure from the Commission's historical acceptance of ''up to'' rates for short-term energy sales, including sales of one week or less, and sought comment on whether to continue to apply a default rate for such sales that is tied to incremental cost plus 10 percent. The Commission sought comment as to: (i) Whether there are problems associated with using ''up to'' rates for shorter-term sales and, if so, what are they; (ii) whether the current approach provides utilities a disincentive to offer their power to wholesale customers in their local control area for short-term sales; and (iii) whether an ''up to'' rate adequately mitigates market power for such sales.

[615] PG&E at 16–17.

[616] PG&E at 17.

[617] Southern at 49.

[618] Southern at 50.

[619] EEI at 46–49.

[620] Southern at 44–52. Southern also asks that the Commission revise the affiliate abuse regulations to include a definition of ''pooled system affiliates'' and clarify that the definition of non-regulated power sales affiliate excludes ''pooled system affiliates'' of traditional franchised utilities. Southern states that any definition of ''pooled system affiliates'' should address both existing arrangements (that have been reviewed and approved by the Commission) and prospective arrangements.

[621] Southern at 48–52.

[622] As proposed in the NOPR, the separation of functions provision provided that ''entities acting on behalf of and for the benefit of a franchised public utility (such as entities managing the generation assets of the franchised public utility) are considered part of the franchised public utility.'' In this Final Rule, we modify the parenthetical in that provision to state: ''(such as entities controlling or marketing power from the electrical generation assets of the franchised public utility).'' See 18 CFR 35.39(c)(1).

[623] April 14 Order, 107 FERC ¶ 61,018 at P 151; *see also* NOPR at P 22, 137.

[624] In a number of instances, the NOPR referred to these sales as ''sales of less than one week,'' and a number of commenters likewise used ''sales of less than one week'' in their comments. We clarify that the reference in the NOPR should have been to ''sales of one week or less,'' consistent with the April 14 and July 8 Orders. Accordingly, for purposes of this Final Rule, we use ''sales of one week or less'' even if the commenters used ''sales of less than one week.''

Comments

607. While not opposing the default rate, APPA/TAPS state that as an alternative, sales of one week or less could occur under the traditional ''split the savings'' methodology.[625] APPA/TAPS submit that both of these methods are consistent with the Commission's observation that ''[a]bsent market power, a generator would typically run if it had excess power and could cover its incremental costs plus some return.''[626]

608. While the Carolina Agencies claim that sales of one week or less should not carry a capacity charge, they concede that a reasonable contribution to the mitigated supplier's fixed costs may be appropriate (*e.g.*, by including a modest adder over the supplier's incremental cost of energy).[627]

609. NRECA and AARP ask the Commission to retain the incremental cost plus 10 percent methodology for mitigating sales of one week or less.[628] NRECA expresses a concern that the Commission's default cost-based rates (for all three products—sales of one week or less; sales of more than one week but less than one year; and sales of one year or longer) may be subject to gaming by larger public utilities, especially because the sellers hold all of the critical data. It asserts that if sellers have too much leeway in choosing which units they will use to calculate their incremental or embedded costs, the default cost-based rates will not provide an effective rate ceiling, and the purpose of the default mitigation will be undermined. NRECA proposes that the Commission require sellers subject to default cost-based rates to submit both pre- and post-approval filings supporting the mitigated cost-based rates for short- and mid-term sales. NRECA suggests that the seller justify its mitigated rates beforehand by demonstrating its incremental costs or embedded costs, as appropriate, and then file after-the-fact quarterly reports of the actual sales and the actual incremental or embedded costs incurred in making these sales.[629] NRECA suggests that this approach would subject mitigated cost-based rate sales to a cost-based formula rate, and therefore to refund, upon Commission review of the quarterly compliance filing.[630]

610. NASUCA urges the Commission to require that all mitigated rates, and any rate discounts, whether for more or less than one year in duration, must be filed and made subject to public scrutiny and Commission review under section 205 of the FPA.[631] NASUCA is concerned that under the NOPR, only rates to be in effect for more than one year are required to be filed publicly in advance and subject to protest, intervention, prior Commission review and revision. It argues, however, that section 205 contains no exception from the filing requirement for sales of less than one year.[632] Given that all new rate schedules and contracts affecting rates must be publicly filed, NASUCA asks the Commission not to reduce section 205's procedural safeguards for sales of less than one year at cost-based rates (*i.e.*, by not requiring that they be subject to prior notice and review).[633]

611. Some commenters oppose the incremental cost plus 10 percent default rate, with several alleging that it deviates from prior Commission precedent without sufficient justification and fails to adequately compensate sellers.[634] Some commenters also allege that such an approach will deter new entry and gives sellers the incentive to sell outside the mitigated market.

612. For example, Westar states that the Commission's reasoning in the July 8 Order which explained that the cost plus 10 percent default rate represents a ''conservative proxy for a reasonable margin available in a competitive market,''[635] suffers from two fatal flaws. First, the Commission failed to distinguish or even mention *Terra Comfort* wherein, Westar and Duke submit, the Commission found that 10 percent adders provide no contribution to fixed costs, and it rejected the argument that ''utilities routinely forego these margins and sell at 110 percent of incremental cost.''[636] Second, according to Westar, in adopting this default rate the Commission relied heavily upon an order that applied the formula in an RTO under entirely different circumstances.[637]

613. MidAmerican and Westar note that, in support of the default rate, in the April 14 Order the Commission cited a PJM tariff provision pursuant to which generators dispatched out of economic merit have their bids mitigated to incremental costs plus 10 percent to prevent them from exercising market power and, at the same time, providing revenues which include a margin.[638] MidAmerican and Westar contend that this is merely an example of a mitigation mechanism, not a rationale for a broad-scale default mitigation scheme that ignores years of precedent.[639] They submit that the PJM tariff mitigates bids for a select set of generators. They state that, regardless of the level of their bids, those generators are still paid the market clearing price because only the offer is capped. Further, because PJM's methodology applied this offer cap only to a limited number of hours, MidAmerican and Westar state that sellers were also free to bid above the cap in the majority of the hours of the year.[640] In contrast, MidAmerican and Westar claim that the incremental cost plus 10 percent default rate is an absolute cap on revenues that would apply to all sales of one week or less in length.[641]

614. Although the July 8 Order explained that incremental cost plus 10 percent was a backstop, default rate, and that entities were free to propose alternative mitigation schemes, MidAmerican asserts that this ignores the fact that the Commission has routinely accepted alternative cost-based rates for sales of one week or less. As such, MidAmerican maintains that there is no reason why ''split the savings'' rates, or rates reflecting a demand charge, could not be used as a default rate for mitigated sales of one week or less.[642]

615. Several commenters also argue that the energy-only incremental cost plus 10 percent methodology does not allow for proper recovery of capacity-based costs on sales of one week or less thereby artificially depressing the prices of these short-term sales and possibly deterring new entry.[643] These commenters state that sellers should be

[625] APPA/TAPS at 45–46.

[626] *Id.* (quoting April 14 Order, 107 FERC ¶ 61,018 at P 152).

[627] Carolina Agencies at 11.

[628] NRECA at 30; AARP at 8.

[629] Suez/Chevron voice a similar concern, adding that a true-up provision would also help improve transparency with regard to the cost of mitigated sales for the benefit of state commissions. Suez/Chevron at 13–14.

[630] NRECA at 30–32.

[631] NASUCA at 18–19; NASUCA reply comments at 16–18.

[632] NASUCA at 18 (citing NOPR at P 22).

[633] *Id.* at 18–19.

[634] MidAmerican at 9–11, Westar at 24.

[635] July 8 Order, 108 FERC ¶ 61,026 at P 155.

[636] Westar at 24 (quoting *Terra Comfort Corp.*, 52 FERC ¶ 61,241 at 61,839–40 (1990)); Duke at 8–9, n.9.

[637] Westar at 25 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, at 61,366 (2004), *order on reh'g, PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 (2005)).

[638] April 14 Order, 107 FERC ¶ 61,018 at P 152, n.146.

[639] MidAmerican at 10; Westar at 25.

[640] *Id.*

[641] *Id.*

[642] MidAmerican at 13.

[643] Pinnacle at 10; Ameren at 15; Duke at 8; MidAmerican at 9–11; Westar at 24; Drs. Broehm and Fox-Penner at 15–16; Xcel at 9; Progress Energy at 9; PPL reply comments at 17–18; EEI at 29; NRG at 5, 11.

allowed to recover a contribution to their fixed/capacity costs.

616. Some commenters contend that the default cost-based rates create an incentive to sell outside the mitigated market because they recover less than cost-based rates historically accepted that included a demand charge. However, they assert that setting rates that require buyers to make a reasonable contribution to the seller's fixed costs for the use of the capacity would create an incentive for the seller to make sales within its mitigated control area.[644] Duke and the Oregon Commission add that allowing recovery of capacity-based costs also ensures that wholesale customers bear their fair share of system costs.[645]

617. Several commenters also claim that by artificially depressing short-term sales prices, the default rate transfers wealth from the supplier's retail customers to wholesale customers.[646] Such retail customers, these commenters state, have paid the fully-allocated costs of the system and obtain revenue credits to their costs from the supplier's short-term sales. Where short-term sales are made on a non-interruptible basis, and the incremental cost plus 10 percent rate prices them only at incremental running cost, Progress Energy contends that wholesale purchasers are receiving the benefits of capacity without cost.[647] Progress Energy and EEI submit that retail native load customers, as a result, lose the economic benefits that would otherwise accrue to them through revenue credits from short-term wholesale sales.[648] Wholesale customers charged through an embedded cost-of-service are also harmed, Progress Energy adds, because they lose the economic benefits that would otherwise accrue to them through revenue credits from short-term wholesale sales.[649]

618. Progress Energy and Duke instead favor an ''up to'' cost-based default rate for sales of one week or less.[650] For such sales, Progress Energy supports an ''up to'' rate design flexible enough to allow rates as low as the mitigated seller's incremental costs and as high as 100 percent of the seller's capacity and energy costs. According to Progress Energy, a mitigated seller could choose to make sales as low as its incremental cost when either (1) The unmitigated market price of competing sellers dictates that price, or (2) the mitigated seller needs to sell its excess generation at that price to maintain a minimum generation control margin. Given that there is a short-term market for capacity, Progress Energy asks that the default cost-based rates include a price structure that allows pricing of capacity-only sales.[651]

619. Xcel suggests that the Commission should allow for an even higher emergency price in situations where purchasers need to make a purchase not simply to achieve economic benefits but where the purchaser is capacity deficient. Xcel submits that in such instances, a purchaser plainly obtains a capacity benefit from the purchase of such power. Historically, the Commission has allowed an emergency rate of $100 per MWh for emergency service. Given that gas prices have dramatically increased since that standard rate began to be utilized, Xcel claims that an emergency rate of the higher of cost plus 10 percent or $1,000 per MWh would be appropriate in the present environment.[652]

Commission Determination

620. The Commission will retain the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less, while continuing to allow sellers to propose alternative cost-based methods of mitigation tailored to their particular circumstances. As discussed more fully below, we clarify that in retaining the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less we do not otherwise limit a seller's ability to propose different cost-based rates for sales of one week or less.[653]

621. Although a number of commenters suggest that the Commission should adopt a different default cost-based ratemaking methodology for sales of one week or less, they have failed to persuade us that the existing default rate is inappropriate. As the Commission has previously stated, an incremental cost rate that allows a fair recovery of the incremental cost of generating with a 10 percent adder to provide for a margin over incremental cost is reasonable.[654] Incremental costs plus 10 percent represents a conservative proxy for a reasonable rate available in a competitive market.[655] On this basis, we find incremental cost plus 10 percent to be an appropriate default rate. Moreover, we allow sellers the opportunity to design, support, and propose other cost-based rates that they believe are more appropriate for their particular circumstances.

622. Several commenters note that the Commission has permitted various cost-based rate methodologies prior to the April 14 Order, including a split-the-savings formula. These entities express concern that the use of the incremental cost plus 10 percent methodology as the default mitigation rate for sales of one week or less forecloses the possibility of other cost-based pricing methodologies. However, this is not the case. Rather than precluding alternative mitigation proposals, the April 14 Order allows sellers to propose case-specific tailored mitigation, or adopt the default cost-based rate. The April 14 Order described the default mitigation rate as ''a backstop measure'' intended to ensure a just and reasonable rate.[656] The Commission re-emphasized this in its July 8 Order explaining: ''In the instant case, the 10 percent adder is to be used only as a backstop or default measure *in the event that an applicant does not opt to propose its own mitigation.*''[657]

623. As such, the incremental cost plus 10 percent rate represents a default, cost-based rate to protect customers from the potential exercise of market power and provide sellers regulatory rate certainty by establishing a ''safe harbor.'' Any proposal for alternative cost-based rates will be considered on a case-by-case basis.

624. Further, with regard to including capacity charges in rates for one week or less, a seller may propose to recover such charges and the Commission will consider these charges based on the specific facts and circumstances presented. Rather than ignoring alternative forms of cost-based rates, as some commenters claim, the Commission's policy offers sellers the opportunity to propose such alternatives.

625. Use of the default rate as set forth in the April 14 and July 8 Orders also is not inconsistent with *Terra Comfort,* as some commenters claim. As explained above, contrary to some commenters' allegations, the Commission does not confine mitigated sellers to rates that forego a contribution to fixed/capacity costs. In *Terra Comfort,* the Commission explained that

[644] *See, e.g.,* Duke at 9.

[645] *Id.* at 10; Oregon Commission reply comments at 2.

[646] Westar at 16; Progress Energy at 9; EEI at 33–34; Pinnacle at 10; MidAmerican at 9.

[647] Progress Energy at 9–10.

[648] *Id.* at 10, n.13; EEI at 29.

[649] Progress Energy at 10, n.13.

[650] Progress Energy at 10; Duke at 8.

[651] Progress Energy at 10.

[652] Xcel at 10.

[653] For that matter, we also do not limit a seller's ability to propose and support different cost-based rates for any of the default cost-based rates.

[654] April 14 Order, 107 FERC ¶ 61,018 at P 152.

[655] July 8 Order, 108 FERC ¶ 61,026 at P 155.

[656] April 14 Order, 107 FERC ¶ 61,018 at P 148.

[657] July 8 Order, 108 FERC ¶ 61,026 at P 157 (emphasis added).

''most utilities maintain on file for all services flexible demand charge ceilings designed to reflect a 100-percent contribution to the fixed costs of their facilities.'' [658] The Commission then added that utilities are not obligated to ''forego these margins and sell at 110 percent of incremental costs.'' [659] In the April 14 Order, the Commission, consistent with its holding in *Terra Comfort,* explained that ''as a backstop measure, we will also provide 'default' rates to ensure that wholesale rates do not go into effect, or remain in effect, without assurance that they are just and reasonable.'' [660] Contrary to Duke's assertion that this default rate suggests that sellers do not have economic justification (or need) to recover a share of their fixed/capacity costs in the prices charged for such transactions,[661] the Commission's policy allows ''applicants to propose case-specific mitigation tailored to their particular circumstances that eliminates the ability to exercise market power, or adopt cost-based rates such as the default rates herein.'' [662] The Commission explained in the April 14 Order that ''[p]roposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate.'' [663] Consistent with industry practice and Commission precedent, therefore, where mitigated sellers can properly justify such contributions, they may propose to recover contributions to fixed/capacity costs under the Commission's mitigation policy.

626. Such alternative mitigation has been proposed and accepted. For example, Progress Energy correctly notes that one of its subsidiaries proposed as mitigation—and the Commission approved—a cost-based ''up-to'' capacity charge and a cost-based energy charge for the subsidiary's power sales of less than one year, including sales of one week or less, in the mitigated control area.[664] Progress Energy is correct in observing that this decision was consistent with the Commission's long-standing policy of permitting the pricing of short-term sales at cost-based ''up-to'' capacity charges and cost-based energy charges.[665] Rather than artificially depressing the prices of short-term sales, exacting a wealth transfer, or limiting a seller's ability to respond to market conditions, as Progress suggests, the default cost-based rate for sales of one week or less provides a backstop measure intended to protect customers by ensuring that, in the event a seller loses or relinquishes its market-based rate authority, there is a readily available cost-based rate under which such sellers may choose to transact, and the mitigated seller by establishing a refund floor that provides it with rate certainty.

627. As to some commenters' suggestion that the incremental cost plus 10 percent methodology, and cost-based rates in general, adversely affect retail rates because they exact a wealth transfer from the supplier's retail customers to wholesale customers, the July 8 Order rejected such claims on the ground that they were ''unsupported and speculative.'' [666] Not only do these claims remain unsupported but they suggest that the Commission should allow wholesale rates in excess of a just and reasonable rate. This result would not be just and reasonable. As the Commission stated in the July 8 Order, ''our rate making policy is designed to provide for recovery of prudently incurred costs plus a reasonable return on investment.'' [667] Moreover, the Commission explained that ''the opportunity for the applicants to propose alternative, tailored mitigation measures should allow adequate consideration of the effect on investment and customers.'' [668]

628. We will not adopt Progress Energy's request that the default rate be modified to include a price structure allowing pricing of capacity-only sales. Progress Energy fails to provide adequate justification to provide for such a rate in our default cost-based rates. For example, Progress Energy states that there is a short-term market for capacity-only sales but fails to explain how this market is a power sales market (for which our default cost-based rates apply) rather than an ancillary services market which is not contemplated in the default cost-based power sales rates. Nevertheless, as noted above, a mitigated seller has the opportunity to propose and justify an alternative to the default rate.

629. Similarly, in response to NASUCA's request that the Commission require all mitigated rates and discounts to be filed under section 205 of the FPA, we note that all mitigation proposals must be filed with the Commission for review. These filings are noticed and interested parties are given an opportunity to intervene, comment, or protest the submittal. With regard to discounts, as we explain in the discounting section of this Final Rule, discounts made to customers, like all other rates, are required to be reported in the seller's EQRs.

630. We also note that the Commission stated in the April 14 Order that where a seller proposes to adopt the default cost-based rates (or where it proposes other cost-based rates), it must provide cost support for such rates.[669] The Commission will examine the proposed rates on a case-by-case basis. With regard to sales of one week or less, where the seller fails to provide sufficient cost support, the Commission will direct the seller to submit a compliance filing to provide the formulas and methodology according to which it intends to calculate incremental costs.[670] We note here that, to the extent a seller proposes a cost-based rate formula, we will require the rate formula used be provided for Commission review and such formula included in the cost-based rate tariff including formulas used in calculating incremental cost.

631. The Commission also has set proposed default cost-based rates for hearing when appropriate.[671] We believe that this case-by-case review of proposed default cost-based rates adequately addresses NRECA's and Suez/Chevron's concerns. Moreover, to the extent that an entity contends that a mitigated seller is flowing inappropriate costs through its formula rate, section 206 of the FPA provides a process for filing a complaint.

b. Sales of More Than One Week But Less Than One Year

Commission Proposal

632. In the NOPR, the Commission sought comment on issues related to the design of an ''up to'' cost-based rate. The Commission noted in the NOPR

[658] *Terra Comfort Corp.,* 52 FERC at 61,839.

[659] *Id.*

[660] April 14 Order, 107 FERC ¶ 61,018 at P 148.

[661] Duke at 9 (citing *Terra Comfort,* 52 FERC at 61,839).

[662] April 14 Order, 107 FERC ¶ 61,018 at P 147.

[663] 663 April 14 Order, 107 FERC ¶ 61,018 at n.142.

[664] Carolina Power & Light, 113 FERC ¶ 61,130 at P 23–24 (2005) (citing *Detroit Edison Co.,* 78 FERC ¶ 61,149 (1997) (approving a demand charge for power sales for periods of an hour up to one year); *Illinois Power Co.,* 57 FERC ¶ 61,213, at 61,699–700 (1991) (permitting utilities to include in their rates an amount above incremental costs to provide a contribution to fixed costs)).

[665] Progress Energy at 8–9.

[666] July 8 Order, 108 FERC ¶ 61,026 at P 140, 154.

[667] *Id.* at P 152.

[668] *Id.* at P 154

[669] April 14 Order, 107 FERC ¶ 61,018 at P 208. *See Entergy Services, Inc.,* 115 FERC ¶ 61,260 at P 49 (2006) (accepting cost-based rates based on incremental cost plus 10 percent, noting that filing included the formula and methodology according to which seller intends to calculate incremental costs).

[670] *See, e.g., Aquila, Inc.,* 112 FERC ¶ 61,307 at P 26 (2005); *Oklahoma Gas and Electric Co.,* 114 FERC ¶ 61,297 at P 19 (2006).

[671] *AEP Power Marketing, Inc.,* 112 FERC ¶ 61,047 at P 28 (2005).

that it has allowed significant flexibility in designing ''up to'' rates in the past, and invited comments on whether such flexibility is still warranted. In particular, the Commission noted that there are often disputes over which units are ''most likely to participate'' or ''could participate'' in coordinated sales, and asked if it should continue to allow utilities flexibility in selecting the particular units that form the basis of the ''up to'' rate. If not, the Commission asked which units should form the basis of an ''up to'' rate, and how such a rate should be calculated. In addition, parties were invited to comment on whether a standard rate methodology should be prescribed that would allow a seller to avoid a hearing on this issue. The Commission asked whether a methodology that is based on average costs (both variable and embedded) would allow a seller to avoid a hearing because it eliminates the seller's discretion in designating particular units as ''likely to participate.'' The Commission also inquired as to whether there are other approaches that would accomplish a similar objective.

Comments

i. Selecting the Particular Units That Form the Basis of the ''Up to'' Rate

633. Regarding whether the Commission should continue to allow utilities flexibility in selecting the particular units that form the basis of the ''up to'' rate, EEI argues for flexibility because selection of generating units for these short-terms sales is made with the goal of minimizing the cost-of-service to the utility's native load customers.[672] Several commenters note that the Commission has the ability to verify the validity of the seller's analysis through an audit of the company's records to monitor transactions made under the ''up to'' rates.[673]

634. Pinnacle asks the Commission to establish a stacking methodology that determines default units most likely to run while allowing utilities to propose a different stack based on historical operational sales data. Pinnacle also urges the Commission to clarify that the variable cost for the unit can be defined as the system incremental cost.[674]

635. Other commenters raise concerns with respect to the discretion given to utilities to choose units used to calculate the ceiling.[675] They submit that taking only a small snapshot of certain generating plants to develop cost-based rates will subject buyers to the discretion of sellers possessing market power.

636. APPA/TAPS, the Carolina Agencies and AARP oppose allowing mitigated sellers too much flexibility in designing mitigation methods on the grounds that such an approach would result in market-based rates disguised as cost-based mitigated rates.[676] For mid-term sales, APPA/TAPS and AARP urge the Commission to require a well-supported analysis of the units most likely to provide the service.[677]

637. The Carolina Agencies ask the Commission to consider whether pricing service based on the costs of units ''likely to participate'' is sufficiently rigorous to meet the operative statutory standards. They oppose the ''units most likely to participate'' method on the basis that the cost and dispatch assumptions used in the underlying analyses are subjective and difficult to verify. The Carolina Agencies state that the identified ''likely to participate'' units often wind up being those units on the system with the highest fixed costs, regardless of whether the units are of a type that one might expect to be cycled or ramped for short-term sales. If mitigated utilities are allowed to continue using this method, the Carolina Agencies urge the Commission to develop a set of generic guidelines that will yield more rigorous, less subjective analyses.[678]

ii. Standard Default Rate Methodology To Allow a Seller To Avoid a Hearing

638. With regard to whether a standard methodology should be prescribed that would allow a seller to avoid a hearing on rate methodology (*e.g.*, a methodology that is based on average costs (both variable and embedded)), many commenters urge the Commission to continue to allow flexibility rather than imposing a standard methodology based on average costs.[679]

639. Westar argues that the use of a standard methodology based on average costs would constitute a radical departure from long-settled Commission policy. Westar states that in Opinion No. 203, the Commission found that cost-based pricing cannot keep pace with fluctuating markets,[680] and that imposing average cost pricing would only exacerbate the market inefficiencies that result under cost-based rate making by eliminating pricing flexibility and lowering ceiling rates.[681]

640. Westar adds that public utilities have the statutory right under section 205 to propose and file their rates, and that the Commission lacks the power to impose rates upon public utilities.[682] Westar therefore opposes standardizing cost-based rates in any manner that would curb a mitigated seller's section 205 discretion to select a pricing methodology.[683] Westar contends that the Commission's section 206 authority to require rate changes is limited to instances where the Commission finds that the utility's presumptively just and reasonable existing rate is unjust and unreasonable, and that the Commission's proposed alternative is just and reasonable.[684] According to Westar, the NOPR offers no support for a finding that the wide variety of previously approved cost-based rate methodologies are no longer just and reasonable, and must be replaced with a standardized rate method.[685]

641. Duke and PPL support ''up to'' rates[686] based on the embedded costs of

[672] EEI at 30–31.

[673] MidAmerican at 12; Duke reply comments at 14; EEI reply comments at 20.

[674] Pinnacle at 11.

[675] *See, e.g.*, NC Towns at 4–5; NRECA at 30–32 (utilities with a portfolio of generation units of various vintages and operating characteristics could manipulate the rate ceiling and undermine mitigation).

[676] APPA/TAPS at 44–45; Carolina Agencies at 24–25; AARP at 8.

[677] APPA/TAPS at 46; AARP at 8. Alternatively, both APPA/TAPS and the Carolina Agencies agree that the Commission's proposal to use an average embedded cost basis for mid-term sales would be acceptable and would avoid the need to make determinations about units most likely to run. APPA/TAPS at 4, 44–47; Carolina Agencies at 24.

[678] Carolina Agencies at 24.

[679] *See, e.g.*, Westar at 14; MidAmerican at 11; PPL reply comments at 17–18; Southern at 66–67; Duke at 10; Progress Energy at 10–12; Xcel at 10; EEI at 30–31.

[680] Similarly, Southern states that the use of an ''up to'' rate design protects customers against unreasonably high prices (the purpose of mitigation in the first place), while giving mitigated sellers the ability to respond to pricing and market dynamics. Southern at 66; *see also* EEI reply comments at 19–20; Xcel at 10.

[681] Westar at 14, 23.

[682] *Id.* at 17–18, 23–24 (*citing Atlantic City Electric Company* v. *FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002)).

[683] *See* Westar at 14, n.26 (claiming that an average cost methodology would eliminate the seller's discretion in designating particular units as ''likely to participate'' in cost-based sales and conflicts with utilities' fundamental rights under section 205 of the FPA, and long-standing precedent under the ''units most likely'' methodology.)

[684] *Id.* at 18 (citing *Tennessee Gas Pipeline Company* v. *FERC,* 860 F.2d 446, 456 (D.C. Cir. 1988)); *see also id.* at 23–24. *See also* MidAmerican reply comments at 22.

[685] Westar at 24.

[686] Drs. Broehm and Fox-Penner also support the use of an ''up to'' rate because it offers flexibility in conducting transactions. However, they suggest a methodology that reflects the incremental cost of new entry to encourage new investment and allow sellers a reasonable opportunity to earn a fair return on their investment. According to Drs. Broehm and Fox-Penner, the weakness of setting a price cap based on embedded cost stems from disputes that

Continued

the units most likely to provide the service.[687] According to Duke, the average costs of all units in a utility's installed generating capacity base could be quite different than the costs of the specific units most likely to participate in the short-term wholesale market.[688] As such, Duke claims that a system-average cost approach could force the mitigated seller to charge non-native load customers less than the cost actually incurred for generating power whenever incremental costs are greater than average costs, thereby creating a disincentive for the mitigated seller to market wholesale power in a control area where it does not have market-based rate authority.[689]

642. Progress Energy states that it opposes a standardized methodology because it will not send appropriate price signals to customers or appropriately compensate the seller for costs where the seller's generating units or the customer's usage deviates materially from the standardized methodology. Rather than adopting a ''units most likely'' approach, Progress Energy prefers a methodology that identifies units based on load conditions that are more closely associated with typical market clearing opportunities, between the average of monthly minimum loads and the average of monthly peak loads. Such an approach, Progress Energy argues, better represents conditions where sales occur.[690]

643. While supporting flexibility in the design of up-to rates,[691] Ameren urges the Commission to prescribe a standard methodology that sellers could opt to use to avoid prolonged and costly factual disputes. Ameren asserts that a formula rate based on information from FERC Form No. 1, where available, and incorporating the AEP Methodology[692] could easily form the basis of such a standard methodology.[693]

644. Because of concerns with regard to the discretion given to sellers to choose units used to calculate the cost-based rate, the NC Towns assert that a standard, system-average ratemaking methodology would provide a certainty beneficial to both utilities and wholesale customers, as well as help reduce protracted negotiations and litigation surrounding parties' concepts of a cost-based rate.[694]

645. For mid-term sales that carry a capacity charge, the Carolina Agencies contend that charge should be based on the utility's fully allocated system-wide cost of capacity. The Carolina Agencies state that energy associated with the purchased capacity also should be priced on a system average basis, in order to adhere to the principle that capacity and energy charges be developed on a consistent basis.[695] For these mid-term sales, the Carolina Agencies also support giving Load Serving Entities (LSEs) located within the mitigated utility's control area an option between: (1) Locking-in their price for capacity and/or energy in advance of delivery, at the mitigated utility's forecasted cost of energy and its cost-based tariff rate for capacity; or (2) having their charges determined through a formula rate that would charge purchasers an annually-updated price reflecting the utility's actual system-wide average costs.[696]

646. The Carolina Agencies add that any change in the Commission's pricing policy that would yield more reasonable cost-based rates must be coupled with a ''must-offer'' requirement. Lower cost-based rates without a concurrent ''must-offer'' requirement, they argue, will only provide the mitigated utility with an even greater incentive to sell all its available power beyond the mitigated region, thereby exacerbating the problems of depleted supply and profiteering by remaining suppliers.[697]

647. For mid-term sales, NRECA asks the Commission to enforce a matching or consistency principle. Here, NRECA advocates using the same generating units ''as the basis for the fixed and variable costs in determining the default embedded-cost rate. In no case should a seller be allowed to mix high-fixed-cost units with high-variable-cost units to artificially inflate the embedded-cost rate. If a seller can show that a portfolio of generating units is likely to be used to provide service, then the seller might be permitted to use a weighted average of the fixed and variable costs of the portfolio.''[698]

Commission Determination

648. Under the Commission's current policy, the default mitigation rate for mid-term sales (sales of more than one week but less than one year) is priced at an embedded cost ''up to'' rate reflecting the costs of the unit(s) expected to provide the service. The Commission will retain this approach as the default mitigation for mid-term sales. As is the case with sales for one week or less, sellers may choose to adopt the default cost-based rate or propose alternative cost-based rates.

Selecting the Particular Units That Form the Basis of the ''Up to'' Rate

649. When a seller adopts the default cost-based mid-term rate or otherwise proposes a cost-based rate designed on the unit or units expected to run, the Commission will continue to allow the seller flexibility in selecting the particular units that form the basis of the ''up to'' rate. Entities that included various proposals for ''up to'' cost-based rate methodologies in their comments may propose those or other methodologies as alternatives to the default cost-based rates, and the Commission will consider any such proposal on a case-by-case basis. Any seller proposing an alternative mitigation methodology, including a cost-based methodology with demand or capacity charges, carries the burden of justifying its proposal.

650. We agree with commenters that the Commission has the ability to verify the validity of the seller's analysis and will continue to do so in our review of proposed cost-based rates. We will continue to conduct our own analysis of whether a proposed cost-based rate is just and reasonable and, if warranted, will set such a proposed rate for evidentiary hearing where there are issues of material fact.

651. In response to the concerns raised by some commenters regarding the discretion given to sellers in the design of ''up-to'' rates, as noted above, the Commission considers all evidence when reviewing a cost-based rate proposal and, if a company has not justified selection of certain generating

arise over which units are selected as the basis for the price cap. Because the cost of new entry methodology would allow the price cap to be formulaic and generic based on the estimate of the annualized total cost of building a new combustion turbine peaking facility, they suggest that this approach would minimize discretion in determining the foundation of a cost-based rate. Drs. Broehm and Fox-Penner at 16.

[687] Duke at 10; Duke reply comments at 13–14; PPL reply comments at 17–18.

[688] Duke at 10; *see also* MidAmerican at 9–11; PPL reply comments at 17–18; Southern at 66–67.

[689] Duke at 10; Duke reply comments at 14.

[690] Progress Energy at 11–12.

[691] Ameren maintains that allowing mitigated sellers to sell at cost-based ''up to'' rates from which the seller may discount adequately mitigates the seller's market power while still allowing that entity to participate in competitive markets. Ameren states that ''up to'' rates thus can benefit customers by resulting in a more robust market. Ameren at 15.

[692] *American Electric Power Company,* 88 FERC ¶ 61,141 at 61,453–54 (1999). Under this methodology, Ameren explains that a seller must develop a cost-based annual rate, which then is divided by 52 to derive a weekly rate, which then is divided by 5 to derive a daily peak rate, which then is divided by 16 to derive an hourly peak rate. Ameren at 15.

[693] Ameren at 16.

[694] NC Towns at 4–5.

[695] Carolina Agencies at 11; *see also* APPA/TAPS at 46–47, n.50 (*citing Florida Power & Light Co.,* 66 FERC ¶ 61,227 at 61,532 (1994)).

[696] Carolina Agencies at 11.

[697] Carolina Agencies at 25.

[698] NRECA at 32.

units, we will not accept the proposed rate. Under the FPA, we have the authority to accept, reject, or modify a proposed rate based on an analysis of the specific facts and circumstances.

652. Further, we find that the approach we adopt in this regard allowing sellers flexibility in designing ''up to'' rates for purposes of mitigation, subject to Commission review and approval, is consistent with the Commission's historical approach to the pricing of cost-based rates. Because the Commission will have the opportunity to review a seller's proposed ''up to'' rates, we find that allowing mitigated sellers flexibility in choosing which units are used to calculate the proposed cost-based rate will not result in market-based rates being disguised as cost-based mitigated rates.

653. In response to Pinnacle's suggestion that the Commission make available a stacking methodology to be used to determine which units are most likely to run, we will do so for informational purposes and will make the methodology available on the FERC Internet site. We also note, however, that sellers may propose to use their own stacking methodology.

654. With regard to the Carolina Agencies' question of whether pricing service based on the costs of units ''likely to participate'' is sufficiently rigorous to meet the operative statutory standards, we find that it is. Historically, the Commission has allowed such an approach and the Carolina Agencies have failed to convince us that, whether or not the underlying analysis is difficult to verify, the approach does not result in just and reasonable rates. In addition, with regard to Carolina Agencies' position with regard to a ''must-offer'' provision, we discuss proposals for a ''must-offer'' provision below in the section on protecting mitigated markets.

Standard Default Rate Methodology To Allow a Seller To Avoid a Hearing

655. Regarding a standard default rate methodology that would allow a seller to avoid a hearing on rate methodology (*e.g.*, a methodology that is based on average costs (both variable and embedded)), we note that the Commission has approved various rate methodologies in the past. Rather than adopting a specific default rate methodology in this Final Rule, we affirm that, to the extent the Commission has previously accepted a particular rate methodology, that methodology is presumed to be just and reasonable until the Commission makes a contrary finding.[699]

656. The Commission will continue to allow sellers flexibility in designing ''up to'' cost-based rate proposals as alternatives to the default methodology. Entities that included various proposals for ''up to'' cost-based rate methodologies in their comments may propose those or other methodologies as alternatives to the default cost-based rates, and the Commission will consider any such proposal on a case-by-case basis.[700] Any seller proposing an alternative mitigation methodology carries the burden of justifying its proposal.

657. We acknowledge that a standard default rate methodology may provide, as several commenters suggest, some level of certainty and avoid prolonged factual disputes. However, we are persuaded by the concerns expressed by others that designing a standard default rate methodology based, for example, on average costs may not account for the actual costs of the units making the sales, and thus may not allow the seller to recover its costs.

c. Sales of One Year or Greater

Comments

658. While the NOPR did not propose changes to the default pricing for long-term sales (sales of one year or more), several entities filed comments on that issue. APPA/TAPS and AARP reiterate their support for pricing such sales on an embedded cost basis.[701] They submit that the Commission should not depart from its default cost-based mitigation policy with regard to long-term sales. The NC Towns also favor using system average costs in a rate base, rate of return model for determining long term cost-based rates.[702] Similarly, the Carolina Agencies assert that long-term sales to embedded LSEs should be priced at the mitigated utility's fully allocated average embedded cost of capacity and system average energy costs. As with short-term sales, the Carolina Agencies urge the Commission to allow the embedded LSEs the choice between: (1) Locking-in their price at the mitigated utility's embedded cost rates; or (2) agreeing to have their charges determined through an annually updated formula rate that reflects the utility's actual system-wide average costs.[703]

Commission Determination

659. We will retain our existing policy for sales of one year or more (long-term) sales. Specifically, we will continue to require mitigated sellers to price long-term sales on an embedded cost of service basis and to file each such contract with the Commission for review and approval prior to the commencement of service.[704] We discuss below the Carolina Agencies' request for a ''must offer'' requirement.

d. Alternative Methods of Mitigation

Commission Proposal

660. In the NOPR, the Commission noted that sellers that are found to have market power (*i.e.*, after the Commission has ruled on a DPT analysis), or that accept a presumption of market power, can either accept the Commission's default cost-based mitigation measures or propose alternative methods of mitigation. With regard to alternative methods of mitigation, the Commission asked in the NOPR whether it should allow as a means of mitigating market power the use of agreements that are not tied to the cost of any particular seller but rather to a group of sellers. The Commission asked whether the use of such agreements as a mitigation measure would satisfy the just and reasonable standard of the FPA.

Comments

661. Many commenters favor allowing alternative mitigation methods tied to the costs of a group of sellers, in particular the Western Systems Power Pool Agreement (WSPP Agreement),[705] or transparent competitive market prices in regional markets. Xcel asserts that the FPA does not require a mitigated rate to reflect a utility's own cost-of-service.[706]

662. E.ON U.S. supports mitigation that sets prices at competitive market

[699] In response to Westar, as discussed herein, Commission precedent supports flexibility in designing cost-based rates and we are not proposing to standardize cost-based rates here. Upon loss or surrender of market-based rate authority a seller has a number of options on how to make wholesale power sales. It can revert to a cost-based rate tariff on file with the Commission, file a new proposed cost-based rate tariff, or propose other mitigation. While we provide a default cost-based rate methodology, we also allow a seller to submit its own cost-based mitigation. On this basis, a seller's filing rights under section 205 of the FPA are not eroded and we are not finding methodologies different from the default methodology necessarily to be unjust and unreasonable.

[700] In response to Pinnacle's request for clarification that the variable cost for the unit can be defined as the system incremental cost, a mitigated seller can make that argument in support of an alternative cost-based mitigation methodology.

[701] APPA/TAPS at 47; AARP at 8.

[702] NC Towns at 4.

[703] Carolina Agencies at 12–13.

[704] April 14 Order, 107 FERC ¶ 61,018 at P 151, 155.

[705] Westar at 26–27; Pinnacle at 10; Ameren at 16–17; PG&E at 22; MidAmerican at 12; Xcel at 8; PPL reply comments at 18; and PNM/Tucson reply comments at 2–3.

[706] Xcel reply comments at 7.

levels. It claims that cost-based rate mitigation eliminates the potential for new competition in a mitigated area. In this regard, E.ON U.S. argues that profits are available only when market prices are below the mitigated utility's cost-based rates, which reduces the incentive for investment in new generation as long as buyers can obtain below market-price energy from generation facilities of the mitigated utility's ratepayers.[707] E.ON U.S. adds that mitigation reflective of competitive prices results in mitigated sellers that are indifferent as to the buyer's location and competitive price signals to which buyers can respond accordingly.[708]

Use of the WSPP Agreement Rate To Mitigate Market Power

663. Several entities suggest that the rates under the WSPP Agreement may be an appropriate alternative mitigation method.[709] Westar asserts that the purpose of the cost-based rate schedules under the WSPP Agreement is to mitigate perceived market power,[710] and notes that the Commission has also accepted use of the WSPP Agreement to mitigate market power in various contexts.[711] Westar contends that parties to the WSPP Agreement may sell under the cost-based rate schedules of the WSPP Agreement regardless of whether they have a separate tariff and authorization from the Commission.[712] Thus, Westar claims that the NOPR's implicit question whether additional authorization is needed to make mitigated sales is misplaced since the WSPP Agreement, as an accepted tariff/rate schedule, establishes the lawful filed rate.

664. Pinnacle notes that the WSPP Agreement's price caps were established based on a system-wide average cost and serve to put entities without market-based rate authority on a similar footing. In Pinnacle's view, such agreements enhance liquidity in the regional markets and facilitate transactions due to the commonality of terms and conditions.[713]

665. PG&E adds that the WSPP Agreement is the most commonly used standardized power sales contract in the electric industry. PG&E states that the WSPP membership continuously updates the WSPP Agreement to ensure that it represents up-to-date terms for power sales contracts and notes that the process of updating its terms involves a diversified, experienced group of market participants focused on developing an appropriate rate for short-term sales. PG&E concludes that the terms of the WSPP tariff should be an accepted alternative rate to the default rate determined by the Commission.[714]

666. In contrast, APPA/TAPS and AARP oppose alternative mitigation methods tied to the costs of a group of sellers because there is no assurance that the group rate would reflect the costs of the seller subject to mitigation.[715] Further, APPA/TAPS have concerns that selecting the appropriate group and obtaining the necessary cost information could be extremely difficult and controversial.[716]

Commission Determination

667. We will address on a case-by-case basis whether the use of an agreement that is not tied to the cost of any particular seller but rather to a group of sellers is an appropriate mitigation measure.

668. With regard to the WSPP Agreement, as discussed below, we conclude that use of the WSPP Agreement may be unjust, unreasonable or unduly discriminatory or preferential for certain sellers. Therefore, in an order being issued concurrently with this Final Rule, the Commission is instituting a proceeding under section 206 of the FPA to investigate whether, for sellers found to have market power or presumed to have market power in a particular market, the WSPP Agreement rate for coordination energy sales is just and reasonable in such market.

669. The WSPP Agreement was initially accepted by the Commission on a non-experimental basis in 1991,[717] providing for flexible pricing for coordination sales and transmission services. Currently, there are over 300 members of the WSPP Agreement located from coast to coast in the United States and Canada, including private, public and governmental entities, financial institutions and aggregators, and wholesale and retail customers. The WSPP Agreement as it exists today permits sellers of electric energy to charge either an uncapped market-based rate (for public utility sellers, they must have obtained separate market-based rate authorization from the Commission to do this), or an ''up to'' cost-based ceiling rate. For sellers without market-based rate authority, the cost-based ceiling rate under the WSPP Agreement consists of an individual seller's forecasted incremental cost plus an ''up-to'' demand charge based on the costs of a sub-set (eighteen sellers) of the original WSPP Agreement members, not necessarily the costs of any one seller. The up-to demand charge is based on the average fixed costs of the generating facilities of that sub-set of WSPP Agreement members; it was designed to reflect the costs of a hypothetical average utility member in 1989. The only limitations are: (1) That the trades by Commission-regulated public utilities must be short-term (lasting one year or less), and (2) that they be priced at or below the ceilings for sellers without market-based rate authority.

670. In a number of recent orders, the Commission accepted the use of the WSPP Agreement as a mitigation measure subject to the outcome of the instant proceeding and any determinations that the Commission makes regarding mitigation in this proceeding. In those cases, we explained that the WSPP Agreement contains a Commission-approved cost-based rate schedule that has been found to be just and reasonable. Further, we noted that parties to the WSPP Agreement have ''the option of transacting under the WSPP Agreement and thus can make sales under the WSPP Agreement without any further authorization from the Commission.''[718]

[707] E.ON U.S. reply comments at 3; *see also* EPSA at 13.

[708] E.ON U.S. reply comments at 3.

[709] *See, e.g.,* Westar at 26 (''The Commission developed and approved the rates under Schedules A and C of the WSPP Agreement as 'rates that are within the zone of reasonableness and that are just and reasonable under the [Federal Power Act]'" (citing *Western Systems Power Pool,* 55 FERC ¶ 61,099, at 61,321 *(WSPP), order on reh'g, Western Systems Power Pool,* 55 FERC ¶ 61,495 (1990), *aff'd in relevant part and remanded in part sub nom. Environmental Action and Consumer Federation of America* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1992), *order on remand,* 66 FERC ¶ 61,201 (1994)); Pinnacle at 10; PG&E at 22.

[710] Westar at 26 (*citing Pacific Gas and Electric Company*, 38 FERC ¶ 61,242 (1987) (accepting WSPP Agreement on experimental basis); *Pacific Gas and Electric Company,* 50 FERC ¶ 61,339 (1990) (reducing the ceiling price on economy energy and capacity service under Schedules A, B and C from $245/MWh to $124/MWh); *WSPP; Western Systems Power Pool*, 83 FERC ¶ 61,099 (1998) (order accepting amendments); *Western Systems Power Pool,* 85 FERC ¶ 61,363 (1998) (Letter Order accepting revised WSPP Agreement); *Western Systems Power Pool, Inc.*, 95 FERC ¶ 61,483 (2001) (order accepting amendments)).

[711] *Id.* (citing, among other cases, *Western Resources, Inc.,* 94 FERC ¶ 61,050, at 61,247 (2001) (accepting WSPP Agreement to mitigate potential affiliate preference concerns between prospective merger partners)).

[712] *Id.* at 27 (citing *NorthPoint Energy Solutions, Inc.,* 107 FERC ¶ 61,181 (2004) (rejecting wholesale cost-based rate tariff as unnecessary in light of seller's intent to make sales under the WSPP Agreement)).

[713] Pinnacle at 10.

[714] PG&E at 22.

[715] APPA/TAPS at 47; AARP at 8.

[716] APPA/TAPS at 41.

[717] *WSPP*, 55 FERC ¶ 61,099 (1991). Prior to 1991, the WSPP Agreement was used for three years on an experimental basis. *See Western Sys. Power Pool,* 50 FERC ¶ 61,339 (1990) (extending the initial two-year period for an additional year).

[718] *Westar Energy, Inc.,* 116 FERC ¶ 61,219 at P 33 (2006); *The Empire Dist. Elec. Co.,* 116 FERC ¶ 61,150 at P 12 (2006); *Xcel Energy Services, Inc.*,

671. Though the Commission has allowed sellers to charge flexible cost-based ceiling rates that are not necessarily based on a particular seller's own costs (such as the WSPP Agreement ceiling rate), we are concerned that the evolution and use of the WSPP Agreement ceiling rate and the evolution of competitive markets have resulted in circumstances in which the WSPP rate may no longer be just and reasonable for sellers that are found to have market power or are presumed to have market power in a particular market, *i.e.*, sellers under the WSPP Agreement that do not have market-based rate authority or that lose or relinquish market-based rate authority.

672. We recognize that the ceiling rate under the WSPP Agreement has been found to be a just and reasonable cost-based rate by this Commission as well as by the U.S. Court of Appeals for the D.C. Circuit,[719] and that it has been in use for over 15 years by sellers irrespective of whether they have market power. Nevertheless, the WSPP Agreement ceiling rate contains extensive pricing flexibility and relies in part on market forces to set the rate at or below the demand charge cap, and we believe the WSPP Agreement rate needs to be revisited in light of its widespread use and changes in electric markets since 1991. When originally approved by the Commission in 1991, there were 40 members under the WSPP Agreement; now there are over 300 members. Additionally, the WSPP Agreement is now used by entities not only in the Western Interconnection, but throughout the continental United States. Further, the demand charge component of the WSPP Agreement ceiling rate is based on the costs of only 18 of the original WSPP members in 1991 (utilizing 1989 data) and does not reflect the costs of the members that joined the agreement since 1991.

673. For these reasons, concurrently with issuance of this Final Rule, we are instituting in Docket No. EL07–69–000 a proceeding under section 206 of the FPA to investigate whether the WSPP Agreement ceiling rate is just and reasonable for a public utility seller in a market in which such seller has been found to have market power or is presumed to have market power. All interested entities will have an opportunity to address this issue through a paper hearing.

674. As noted above, the Commission has accepted, subject to the outcome of this rulemaking proceeding, the use of the WSPP Agreement ceiling rate as mitigation by a number of sellers. These sellers may continue to use the WSPP Agreement ceiling rate as mitigation, subject to refund (and the refund effective date established in Docket No. EL07–69–000) and subject to the outcome of the section 206 proceeding.

Market-Based Proposals for Mitigation

Comments

675. Commenters are generally concerned that where the Commission's current mitigation approach focuses on a seller's own cost of service, it imposes cost-based rates on a mitigated utility in the home control area regardless of whether the prices of alternative sources of supply in the mitigated market exceed the mitigated seller's cost-based rates.[720] Rather than relying on cost-based price caps that may bear no relationship to market conditions, several commenters support allowing mitigation methods based on transparent competitive market prices in regional markets.[721] Commenters suggest various market indicia that the Commission could use as price proxies in market-based mitigation alternatives.[722]

676. Because different markets may be uncompetitive for different reasons, and the same mitigation measure is not necessarily equivalent in all situations, several commenters urge the Commission to consider more tailored, market-based rate approaches to mitigation on a case-by-case basis.[723] MidAmerican suggests that any specific index chosen could be reflected in the tariff of mitigated sellers (for sales up to one year) or in agreements filed with the Commission (for sales of one year or longer).[724]

677. Duke explains that market-based rate mitigation alternatives could be applied to mitigated sellers whose control area markets are adjacent to a Commission-approved market. If the proxy prices are established in markets that the Commission has found to be functionally competitive, Duke contends that the price will by definition be just and reasonable. Duke submits that the Commission approved similar mitigation for sales by the LG&E Parties sinking in the Big Rivers control area capped at the Midwest ISO's LMP at the Big Rivers control area interface.[725]

678. E.ON U.S. argues that allowing index-based price caps as a mitigation option is just and reasonable because such sales are either subject to the market monitoring provisions of an RTO, or in the case of price indices, are structured according to the Commission's instructions with regard to market price reporting. They add that index-based price caps are efficient because: (a) They can be used to address pricing requirements for varying time commitments; (b) they meet the Commission's criteria for accurate and timely reporting; and (c) they do not require the administrative overhead and complexity associated with calculating and reporting cost-based rates.[726]

679. MidAmerican and the Oregon Commission submit that using an appropriate price index as a proxy could ensure that prices are derived from competitive conditions and do not reflect the market power of the mitigated seller (or, for that matter, of *any* seller).[727] Duke, MidAmerican, and the Oregon Commission reason that allowing a published price index would effectively make the mitigated seller a price taker rather than a price setter.[728] E.ON U.S., PNM/Tucson, and Indianapolis P&L also suggest that requiring cost-based mitigation may result in sellers giving up their market-based rate authority in mitigated areas

117 FERC ¶ 61,180 at P 49 (2006). However, we note that a review of EQR data indicates that of 65 sellers reporting contracts under the WSPP Agreement, 56 sellers reported sales under that agreement in 2006. Fifty-five of these sellers reported sales that were identified as market-based rate sales.

[719] *Environmental Action and Consumer Federation of America* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1993).

[720] *See, e.g.*, Xcel at 7–9.

[721] Duke at 3, 13–14; Drs. Broehm and Fox-Penner at 16–17; MidAmerican at 12–13; E.ON U.S. at 10–12; Southern at 65, n. 104, 66; Ameren at 14; Xcel at 8–9; PNM/Tucson at 12,14; EEI at 26–29; Dr. Pace at 23; PPL reply comments at 17–18; and Oregon Commission reply comments at 2–3.

[722] For example, Duke (prices from an adjoining LMP market that are transparent and contemporaneously available); MidAmerican (reference prices for the region or from neighboring LMP markets, published index prices reported by public subscription services, or prices capped at levels reported in the Commission's Electric Quarterly Report for sales in neighboring markets); Xcel (proximate price indexes where available, the WSPP Agreement, a utility's own sales in areas where it does not possess market power, competitive solicitations with a sufficient amount of bidders or opportunity cost pricing); EEI (published index prices at liquid regional trading hubs or LMP nodal prices for adjacent Day 2 RTOs); the Oregon Commission (price at a frequently traded energy hub or an LMP determined by an adjoining RTO would be appropriate price indexes). If an appropriate and valid price index is not available, the Oregon Commission would require the seller to make mitigated sales at cost-based rates.

[723] MidAmerican at 14; NYISO at 8; Duke at 13–14; Drs. Broehm and Fox-Penner at 15.

[724] MidAmerican reply comments at 5.

[725] Duke at 14 (citing *LG&E Energy Marketing Inc.,* 113 FERC ¶ 61,229 at P 30 (2005)).

[726] E.ON U.S. at 12.

[727] MidAmerican at 13; Oregon Commission reply comments at 2; *see also* PPL reply comments at 17–18.

[728] Duke at 14; MidAmerican at 13–14; Oregon Commission reply comments at 2.

due to the significant time and expense of developing a cost-of-service filing.[729] Where sellers opt to give up market-based rate authority, these commenters conclude that buyers will be harmed by a reduction in the number of competitive options available to them in mitigated markets.

680. MidAmerican claims that using price indices would (a) Eliminate the incentive for round-trip transactions; (b) alleviate the need to determine whether the need for mitigation should be based on the point of delivery, the sink location, or some other determinant; and (c) reduce contention over how to calculate cost-based rates.[730] EEI and the Oregon Commission conclude that allowing mitigated rates to be based on competitive market prices would: (1) Maintain supply choices for captive customers by encouraging mitigated suppliers to participate actively in the mitigated markets; (2) avoid the unintended consequences of cost-based rate mitigation (*e.g.*, incentive to sell outside the mitigated region); (3) help to ensure that buyers continue to receive accurate price signals and not inappropriately lean on cost-based rates in times of peak demand; and (4) be consistent with the Commission's goal of encouraging competitive market solutions.[731]

681. APPA/TAPS reject this reasoning, arguing that a dominant supplier has other incentives not to sell to captive customers beyond just the availability of a higher price elsewhere, including the desire to disadvantage competing suppliers within its control area. Therefore, even if a market price index is used as a mitigation alternative, APPA/TAPS submit that a ''must offer'' obligation remains necessary.[732]

682. According to some commenters, capping mitigated prices at the levels of relevant price indices would also reduce the market distortions that exist under dual price systems.[733] E.ON U.S., Xcel, PNM/Tucson, Duke, EEI, MidAmerican and the Oregon Commission generally contend that allowing market-based rate mitigation methods would reduce the incentive, arising from price disparities in dual-price systems (a regime where a seller has market-based rate authority in some markets but is limited to cost-based sales in other market(s)), for mitigated sellers to seek market-based rate sales beyond the mitigated market.[734] This, in turn, would obviate the need for a ''must offer'' requirement or mitigation of sales outside the mitigated region. Somewhat similarly, EEI warns that if the Commission implements a ''must offer'' obligation, suppliers may not apply for market-based rate authorization in markets where they are likely to fail any of the market power screens.[735]

683. Some commenters add that the Commission surrenders nothing in terms of consumer protection by allowing market-based price caps as a mitigation option. In their view, permitting such mitigation will likely increase the willingness of sellers to engage in market transactions in mitigated areas and result in buyers paying no more than what is already recognized as a just and reasonable competitive market price.[736]

684. MidAmerican, E.ON U.S., PNM/Tucson, and Indianapolis P&L all note that the Commission (1) Has found that inter-affiliate sales are permissible at RTO price indices, and (2) proposes in the NOPR (at P 113–14) to extend this policy to market indices satisfying the November 19 Price Index Order.[737] These commenters argue that if sales at a meaningful market index are *per se* just and reasonable for affiliate transactions, there is no reason why such sales are not *per se* just and reasonable for non-affiliate transactions.[738] PNM/Tucson add that even in regions without organized RTO/ISO markets, sellers with market-based rate authority have established highly liquid trading hubs (*e.g.*, Four Corners or Palo Verde) that also produce market prices that are readily available, transparent, can serve as an appropriate proxy, and satisfy the Commission's index pricing standards.[739]

685. Another commenter supports the adoption of more market-oriented approaches to mitigation. For daily and hourly transactions, this commenter asks the Commission to be receptive to rates tied to an acceptable price index at a liquid trading point. For long term transactions, rather than focusing on average embedded costs, which this commenter claims are likely to be a poor proxy for market rates, the Commission should consider capacity and associated energy rates that provide a competitive rate of return on new generation units built in the region. Where transmission constraints bind only occasionally and the seller does not have market power absent such constraints, this commenter reasons that it is rational to only apply mitigated rates to sales made at the time such constraints are binding. Similarly, where indicative screens or the DPT analysis point to the existence of a market power problem in a well-defined seasonal or peak period, this commenter favors confining rate mitigation to sales made in the relevant market during that period.[740]

686. APPA/TAPS acknowledge that cost-based rates do not achieve competitive wholesale markets.[741] Ideally, wholesale customers should have a meaningful choice of suppliers whose costs are disciplined by competitive forces and remedies focused on fostering structurally competitive markets will help to ensure that future consumers have choices. Until such structural remedies are fully implemented, APPA/TAPS maintain that mitigated sellers should sell at cost-based rates.[742]

687. APPA/TAPS and Morgan Stanley do not categorically oppose the use of price indices as a mitigation alternative that could be justified with substantial evidence, but urge caution and ask the Commission not to assume that the index relied upon is a just and reasonable, and comparable, proxy for the mitigated market.[743] Morgan Stanley explains that given the price variation among transmission nodes, it is not possible to generically find that any one index-based price would be an adequate proxy for another node(s). APPA/TAPS explain that a thinly traded market, or one separated by transmission constraints, could create volatility or arbitrage possibilities that would leave captive customers worse-off than a cost-based mitigated rate. They add that appropriate price proxies may not be available for all products, and that RTO-administered real-time or day-ahead markets would not generally provide acceptable proxies for price mitigation in markets for weekly, monthly or annual sales. APPA/TAPS also note that the Southeast has no real liquid trading hubs.[744] While urging the Commission to continue requiring cost-based mitigation, Morgan Stanley does not oppose allowing mitigated sellers to

[729] Indianapolis P&L at 11; E.ON U.S. at 11; PNM/Tucson at 13.

[730] MidAmerican reply comments at 3–4, 20.

[731] EEI reply comments at 12; Oregon Commission reply comments at 3.

[732] APPA/TAPS reply comments at 15.

[733] PNM/Tuscon at 13–14; MidAmerican at 14; EEI at 26; *see also,* CAISO at 6.

[734] E.ON U.S. at 10–11; Xcel at 8–9; PNM/Tucson at 13; Duke at 9; EEI at 28; MidAmerican at 14; Oregon Commission reply comments at 3.

[735] EEI reply comments at 18.

[736] Duke at 14; APPA/TAPS at 64; MidAmerican at 13.

[737] MidAmerican at 13; E.ON U.S. at 11; PNM/Tucson at 12; Indianapolis P&L at 7.

[738] E.ON U.S. at 11; Indianapolis P&L at 11; MidAmerican reply comments at 5.

[739] PNM/Tucson at 13.

[740] Dr. Pace at 23–24.

[741] APPA/TAPS at 48.

[742] *Id.* at 48–49.

[743] APPA/TAPS reply comments at 13; Morgan Stanley reply comments at 2, 8–10.

[744] APPA/TAPS reply comments at 14–15.

justify an index-based mitigation approach as appropriate for their specific circumstances. According to Morgan Stanley, such an approach may prove justifiable where a viable, liquid index exists within or adjacent to the territory in which a finding of market power exists.[745]

688. NRECA likewise is concerned that there is no assurance that (1) The external market price would be a competitive price; (2) external markets are a reasonable proxy for non-existent competitive market prices in the mitigated market; and (3) there are sufficient monitoring and enforcement mechanisms to ensure these first two conditions are continually being met.[746] Unless these three concerns are addressed, NRECA asserts that the Commission may not lawfully rely on an external market price as a proxy in a mitigated market, particularly where the FPA is clear that the Commission may not approve market-based rates absent ''empirical proof'' that ''existing competition would ensure that the actual price is just and reasonable.''[747] Moreover, where ''Congress could not have assumed that 'just and reasonable' rates could conclusively be determined by reference to market price,'' [748] NRECA argues that the Commission may not rely exclusively on market prices but rather must have a regulatory ''escape hatch'' or ''safeguard'' mechanism [749] if actual competitive pressures alone cannot keep rates just and reasonable. NRECA, similar to APPA/TAPS, is concerned that proxy indices are irrelevant oftentimes because they are too far removed from the mitigated market to be adequately representative. While NRECA admits that such indices may be adequate in some instances, it takes the position that, at most, the Commission could entertain proxy index proposals from mitigated sellers on a case-by-case basis.[750]

689. The Carolina Agencies are similarly concerned that market-based indices based on LMPs from adjacent markets in many hours will reflect transmission congestion that may not be representative of congestion patterns in the mitigated market, and therefore must not be deemed a just and reasonable proxy for an entirely different market. Moreover, LSEs in RTOs with Day 2 markets have some ability to limit their exposure to LMP spikes through the use of hedging tools (*i.e.* Auction Revenue Rights and Financial Transmission Rights). However, the Carolina Agencies argue, LSEs in mitigated markets would face these LMP gyrations from adjacent markets as proxy prices without any hedging protections. These agencies further claim that there are no other sources of non-LMP price information in their region that are reliable enough to serve as proxy prices.[751] In the Carolina Agencies' view, because price information from non-LMP markets is mostly illiquid, non-transparent and easily manipulated due to the low volume of transactions, such reference prices are unlikely to be an accurate and reasonable proxy for competitive prices in the mitigated control area. They state that, as the Commission has reported, ''some electric power markets are almost entirely opaque both to regulators and to price takers. In these markets (such as electricity in the Southeast), so little information is available that price indices either do not develop or have little value in price discovery.'' [752] The Carolina Agencies also wonder how a meaningful proxy could be determined for a market price in a control area where a dominant supplier has market power.[753]

690. The Carolina Agencies and NASUCA oppose providing mitigated utilities with the option of filing cost-based rates or choosing the market rates of a neighboring control area.[754] NASUCA adds that commenters articulate no legal theory by which mitigated sellers should be allowed any market rate or how the Commission has power to grant any waiver of the rate filing and review requirements of section 205 of the FPA.[755] Rather than allowing mitigated rates to be determined by market prices in adjacent market areas, NASUCA urges the Commission to deny any form of market rates to mitigated utilities and require such suppliers to comply with section 205 of the FPA by filing their rates subject to the traditional review to ensure just and reasonable rates.[756]

691. If the presence of transmission constraints in a dominant transmission provider's control area allow it to charge supra-competitive market-based rates there, APPA/TAPS submit that the Commission must require these constraints to be addressed.[757] These commenters ask the Commission to impose mitigating conditions on market-based rate authority to increase access to existing transmission facilities as well as to expand their transmission access through rolled-in upgrades. For example, APPA/TAPS,[758] and the Carolina Agencies [759] suggest that the Commission could condition the market-based rate authority of a mitigated seller on the demonstrated willingness of vertically-integrated transmission owners to jointly plan and construct new generation projects with market participants, and/or to participate with them in collaborative, open regional transmission planning processes.

692. Xcel responds that, aside from such a requirement being impractical, the Commission has no legal authority to impose a condition requiring joint planning of new facilities nor jurisdiction over the construction of new facilities.[760] Xcel states that the FPA does not provide the Commission with certificate jurisdiction over generation facilities or otherwise, nor does the Commission have the authority to order utilities to enter into such a contract.[761]

Commission Determination

693. The Commission continues to believe that proposed alternative methods of mitigation should be cost-based. However, as discussed below, while we will not allow the use of alternative ''market-based'' mitigation on a generic basis, we will permit sellers to submit alternative non-cost-based mitigation proposals for Commission consideration on a case-by-case basis.

694. A variety of suggestions have been made such as basing mitigated prices on: Prices from an adjoining LMP market that are transparent and contemporaneously available; published index prices; prices capped at levels reported in the Electric Quarterly Reports for sales in neighboring markets; a utility's own sales in areas where it does not possess market power;

[745] Morgan Stanley reply comments at 9–10.

[746] NRECA reply comments at 31–33.

[747] *Id.* at 32 (*quoting Farmers Union Cent. Exch., Inc.* v. *FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984)).

[748] *Id.* (*quoting FPC* v. *Texaco,* 417 U.S. 380, 399 (1974)).

[749] *Id.* (*quoting Louisiana Energy & Power Auth.* v. *FERC,* 141 F.3d 364, 370–71 (D.C. Cir. 1998)).

[750] *Id.* at 33.

[751] Carolina Agencies reply comments at 2–3, 10, 14–18.

[752] *Id.* at 18, n. 11 (citing Federal Energy Regulatory Commission—Office of Market Oversight and Investigations, *2004 State of the Market Report* (June 2005)).

[753] *Id.* at 15, n. 9.

[754] *Id.* at 18–19; NASUCA reply comments at 18–19.

[755] NASUCA reply comments at 18–19.

[756] *Id.*

[757] APPA/TAPS at 50.

[758] *Id.* at 40–41, 49, 50–51.

[759] Carolina Agencies at 12, n.10.

[760] Xcel reply comments on 9–10.

[761] *Id.* at 10. Duke likewise opposes any proposal granting an automatic entitlement to participate in new generation planned by the mitigated utility, arguing that the commercial terms of any joint ownership arrangements must be negotiated by the parties. Duke reply comments at 11; *see also,* EEI reply comments at 8–9.

and competitive solicitations with a sufficient amount of bidders or opportunity cost pricing. However, while some commenters suggest that market-based rate mitigation may cure several of the cost-based mitigation regime's alleged ailments, they fail to convincingly address a fundamental concern with such mitigation. That is, why a market-based price from one market would be a relevant and appropriate proxy price to mitigate market power found in a different market.

695. Specifically, we reject Duke's argument that we should allow market-based rate mitigation alternatives to be used by mitigated sellers whose control area markets are adjacent to a Commission-approved market because if the proxy prices are established in markets that the Commission has found to be functionally competitive, the price will by definition be just and reasonable. Although Duke is correct that a price in a market may be presumed to be just and reasonable in the market in which it has been approved, Duke's claim fails because that price has not been shown to be just and reasonable for other markets with differing competitive circumstances.[762] Duke's argument also fails to recognize that the Commission does not certify markets as competitive; rather, we make determinations on whether individual sellers in a market have market power. In addition, contrary to Duke's view, the Commission's acceptance of proposed mitigation in the Big Rivers control area does not support Duke's proposal in this regard. In *LG&E Energy Marketing Inc.,*[763] the Commission accepted a proposal that capped—at the Midwest ISO's LMP price at the Big Rivers control area interface—all market-based sales by LG&E sinking in the Big Rivers control area not sold pursuant to contractual agreements already in existence. However, Duke fails to point out that, when LG&E proposed to mitigate its sales into the Big Rivers control area, LG&E was a member of the Midwest ISO and, accordingly, capping LG&E's sales price at the Midwest ISO LMP at the Big Rivers interface was appropriate.

696. Commenters raise many reasons why allowing the use of an index could be beneficial such as: Using an appropriate price index as a proxy could ensure that prices are derived from competitive conditions and do not reflect the market power of the mitigated seller; allowing a published price index would effectively make the mitigated seller a price taker rather than a price setter; use of an index price would eliminate the incentive for round-trip transactions and alleviate the need to determine whether the need for mitigation should be based on the point of delivery, the sink location, or some other determinant; would maintain supply choices for captive customers by encouraging mitigated suppliers to participate actively in the mitigated markets; would help to ensure that buyers continue to receive accurate price signals and not inappropriately lean on cost-based rates in times of peak demand; and, would be consistent with the Commission's goal of encouraging competitive market solutions.

697. However, we agree with Morgan Stanley and others that, given price variations among transmission nodes, we should not generically find that one index-based price is necessarily an adequate proxy for another node. Commenters urging the Commission to consider such alternatives on a case-by-case basis acknowledge that different markets may be uncompetitive for different reasons.[764] While commenters speak of ''relevant price indexes,'' their comments contain little more than undeveloped proposals and limited discussion as to how such an index would be chosen, and why it would be an appropriate proxy for the mitigated market. For example, commenters fail to explain how a proxy price based on existing competition from one market with distinct traits such as transmission congestion ensures a just and reasonable price in another market that has its own unique traits and circumstances. Deriving prices from competitive conditions, making a mitigated seller a price taker rather than a price setter, and reducing market distortions are all goals commenters claim market-based mitigation can help achieve. Nonetheless, the use of an external market price to establish the just and reasonable price in the mitigated market has not yet been shown to be appropriate.

698. While we will not allow the use of ''market-based'' mitigation on a generic basis, we nevertheless will permit sellers to submit non-cost-based mitigation proposals, such as the use of an index or an LMP proxy, for Commission consideration on a case-by-case basis based on their particular circumstances. Sellers choosing to propose such alternative mitigation will carry the burden of showing why and how the proposed index-based price is relevant, appropriate and a just and reasonable price for the mitigated market. While several commenters also seek to have the Commission make market-based rate authorization of mitigated sellers contingent upon their pledging to jointly plan and construct future generation projects with market participants, or pursue other structural conditions, they have not justified imposing such a burden. For those sellers that are affected with a market power concern, we discuss elsewhere in this Final Rule the means by which we will require adequate mitigation. Moreover, we believe that we have adequately addressed these concerns related to planning in our recent Order No. 890, where we require all jurisdictional transmission owners to engage in transmission planning with other market participants. Therefore, we find no reason to mandate a mitigated seller's participation in such arrangements.

2. Discounting

Commission Proposal

699. In the NOPR, the Commission explained that a supplier authorized to sell under an ''up to'' cost-based rate has an incentive to discount its sales price when the market price in the supplier's local area is lower than the cost-based ceiling rate. During these periods, a rational seller will discount its sales to maximize revenue. In the past, the Commission has encouraged discounting as an efficient practice that can maximize revenues to reduce the revenue requirements borne by requirements customers.

700. Here, the primary issue is whether a seller can ''selectively'' discount, *i.e.*, offer different prices to different purchasers of the same product during the same time period. The Commission invited comment on whether selective discounting should be allowed for sellers that are found to have market power or have accepted a presumption of market power and are offering power under cost-based rates. If so, the Commission sought comment on what mechanisms (reporting or otherwise), if any, are necessary to protect against undue discrimination. By contrast, were it to forbid selective discounting, the Commission asked for comment on whether it should require the utility to post discounts to ensure that they are available to all similarly-situated customers.

[762] E.ON U.S.' proposal that the use of index-based price caps subject to the market monitoring provisions of an RTO is a just and reasonable mitigation option equally fails to address whether the index-based price is relevant to the market in which the sale is made.

[763] 113 FERC ¶ 61,229 (2005).

[764] MidAmerican at 14; NYISO at 8; Duke at 13–14; Drs. Broehm and Fox-Penner at 15.

Comments

701. Some commenters favor selective discounting because it provides an opportunity to meet competition where necessary to retain and attract business. They add that the contracting flexibility afforded by selective discounting allows sellers to modify rates and tailor sales based on customer-specific factors such as load characteristics and credit ratings. They argue that such flexibility maximizes liquidity and available capacity and energy.[765]

702. MidAmerican and Indianapolis P&L both state that section 206 of the FPA already prohibits undue discrimination and provides well-established procedures for entities that have been subjected to undue discrimination.[766] Westar notes that the Commission's long-standing policy is to allow selective discounting and asserts that discounting to customers who have competitive alternatives is not unduly discriminatory.[767]

703. PG&E maintains that it is just and reasonable for a seller to offer a discount below its cost-based mitigated rate if the seller will gain other (non-market power) advantages such as repeat customers or lower transaction costs. PG&E also suggests that principles of efficiency and competition support providing selective discounts to entities with larger needs.[768]

704. Duke contends that sales arising from selective discounting spread fixed costs over more units of service, thereby reducing the ''up to'' rate.[769] Moreover, without the ability to selectively discount, Duke submits that utilities will not have the opportunity to compete for many wholesale transactions in the mitigated control area.[770]

705. Southern asserts that if selective discounting were eliminated, then the resulting loss of a low-cost source of supply would harm the customers. In Southern's view, captive customers also lose because of foregone opportunities to optimize capacity nominally dedicated to native load service.[771] EEI adds that where a mitigated seller is already precluded from making market-based rate sales within mitigated areas, selective discounting does not give rise to conditions that support the potential exercise of market power.[772]

706. Other commenters generally oppose allowing mitigated sellers to selectively discount sales. For example, TDU Systems claim that selective discounting is unnecessary because a seller subject to cost-based mitigation in its home control area would not face competition by definition. They also contend that selective discounting would allow mitigated sellers to engage in price discrimination in a non-competitive market, thereby permitting the seller to exercise market power by economically or physically withholding capacity to increase the posited market price. Thus, in the TDU Systems' view, a rule allowing selective discounting would effectively grant market-based rate authority in a non-competitive market, in contravention of the requirements of the FPA.[773]

707. While NC Towns generally encourage discounts to cost-based rates, they oppose selective discounting because they do not believe that the size of a load should be a factor when determining whether to give a buyer a discount.[774]

708. APPA/TAPS question why a dominant seller would offer discounts to captive customers with no other viable supply options. They add that there is no evidence that local, competing generation exists or that there is available transmission capacity that could support significant imports. In order to avoid discrimination, APPA/TAPS advocate requiring a mitigated supplier to offer captive customers any discounts that it offers to other purchasers.[775] Factors such as a customer's capacity factor, credit rating or fuel costs may justify adjustments to seller-specific cost-based rates, but such factors, argue APPA/TAPS, should be reflected in the seller's cost-based rates rather than through selective discounting.[776]

709. If selective discounting is permitted, TDU Systems and NRECA urge the Commission to require sellers to file reports of the discounts offered, and encourage the Commission to vigorously enforce its market manipulation and affiliate transactions rules.[777]

710. Suez/Chevron urges the Commission to require selective discounts to be contemporaneously offered to similarly-situated buyers, and separately identified in the mitigated seller's EQR.[778] To minimize the potential for market power abuse when a mitigated seller selectively discounts to an affiliate,[779] Suez/Chevron supports requiring a presumption that nonaffiliated buyers are similarly-situated, and therefore entitled to the same discount as a mitigated seller offers to its affiliate.[780]

711. PG&E, in contrast, opposes requiring the seller to make discounts available to all similarly-situated entities. According to PG&E, it would be difficult to determine which entities are in fact similarly-situated because the seller would have to consider multiple factors, such as quantity of load, timing, flexibility, credit rating, and purchases history.[781]

712. Ameren disagrees with a posting requirement, arguing that the Commission's requirements for separate filings and advance approval of affiliate power sales provide the appropriate oversight and mechanisms necessary to police discounting concerns regarding selective discounts favoring affiliates. Ameren concludes that a requirement to post discounts is unduly burdensome given that the only discounts of concern are in the affiliate sales, which are subject to separate filing requirements.[782] PG&E, in turn, notes that the affiliate restrictions also provide protection against the use of selective discounts to benefit affiliates.[783]

Commission Determination

713. We will continue our practice of allowing discounting from the default cost-based mitigated rates for short- and mid-term sales and will permit selective discounting by mitigated sellers provided that the sellers do not use such discounting to unduly discriminate or give undue preference. We believe that selective discounting that does not constitute undue discrimination can improve liquidity, available capacity and energy, and customer supply

[765] *See, e.g.,* Indianapolis P&L at 10; MidAmerican at 15–16; Duke at 10–11; EEI at 34; PG&E at 23; Progress Energy at 12.

[766] MidAmerican at 15; Indianapolis P&L at 10.

[767] Westar at 26 (citing *Town of Norwood v. FERC,* 587 F.2d 1306, 1312 & n.17 (D.C. Cir. 1978) (rate disparity may be justified by, *inter alia,* differences in the customers' level of risk aversion and bargaining power)); *see Policy for Selective Discounting by Natural Gas Pipelines,* 111 FERC ¶ 61,309, *reh'g denied,* 113 FERC ¶ 61,173 (2005) (affirming Commission's 16-year policy to allow selective discounting by interstate natural gas pipelines when necessary to meet competition).

[768] PG&E at 23.

[769] Duke at 11.

[770] *Id.*

[771] Southern at 67.

[772] EEI at 31; *see also* PG&E at 23.

[773] TDU Systems at 19–21.

[774] NC Towns at 5.

[775] APPA/TAPS reply comments at 15–16; APPA/TAPS at 44–48.

[776] APPA/TAPS reply comments at 16.

[777] TDU Systems at 24; NRECA at 32.

[778] NC Towns and Morgan Stanley state that any discount the seller wishes to offer should be required to be posted with sufficient time for other interested parties to take advantage of the offer. NC Towns at 5–6; Morgan Stanley at 7.

[779] Suez/Chevron states that sellers should be required to post any affiliate discounts on their OASIS. Suez/Chevron at 13.

[780] Suez/Chevron at 12–13.

[781] PG&E at 24.

[782] Ameren at 17–18.

[783] PG&E at 23.

options. In other words, non-discriminatory discounting can provide benefits to the market.

714. APPA/TAPS question why a dominant seller would offer discounts to captive customers with no other viable supply options, and the TDU Systems comment that selective discounting is unnecessary because a mitigated seller by definition would not face competition in its home control area. However, in times when there are viable alternatives, a seller under an ''up to'' cost-based rate has an incentive to discount its sales price when the market price in the seller's mitigated market is lower than the cost-based ceiling rate. Allowing a mitigated seller to non-discriminatorily discount the rate when there are viable alternatives in the market benefits customers by providing more supply options in such instances.

715. Discounting also can maximize revenue by optimizing capacity nominally dedicated to native load service, allowing the supplier to spread fixed costs over more units of service. Maximizing revenue in this manner can help reduce the ''up to'' rate, and therefore the revenue requirements borne by captive customers. The Commission has previously determined that requiring a mitigated entity to limit sales to its ceiling rates ''is at odds with the long-standing policy of allowing 'up to' cost-based rates.'' [784]

716. The FPA requires that all rates charged by public utilities for the sale or resale of electric energy be ''just and reasonable.'' [785] If a seller's cost-based rate has been found to be just and reasonable by the Commission, it follows that discounted rates below such a cost-based rate are also just and reasonable.[786] However, a seller may not lawfully discount to gain, or profit from, market power advantages. We emphasize that section 205 of the FPA prohibits public utilities, in any power sale subject to the Commission's jurisdiction, from granting any undue preference or advantage to any person [787] and also prohibits undue discrimination.[788]

717. With regard to comments that the Commission establish a reporting mechanism, under the Commission's existing reporting requirements entities making power sales must submit EQRs containing: A summary of the contractual terms and conditions in every effective service agreement for all jurisdictional services, including market-based and cost-based power sales and transmission services; and, transaction information for effective short-term (less than one year) and long-term (one year or greater) power sales during the most recent calendar quarter.[789] Through this reporting requirement, the Commission monitors the rates charged by mitigated sellers.

718. Several commenters also seek to have the Commission require selective discounts to be posted and contemporaneously offered to similarly-situated buyers. Some seek a presumption that nonaffiliated buyers are similarly situated whenever a mitigated seller offers an affiliate a discount. The Commission will not require mitigated sellers to contemporaneously post in a public forum all discounts provided for cost-based sales (*i.e.*, where the sale is made at a price below the maximum up-to cost-based rate approved by the Commission in that tariff or rate schedule). Proponents of a posting requirement have not justified nor demonstrated how the Commission's EQR requirement fails to provide an adequate means by which to monitor such discounts. In addition, many sales are made below the cost-based cap, and the commenters' proposals would place an undue burden on sellers that would be required to contemporaneously post rates that the Commission has already deemed to be just and reasonable. Accordingly, the Commission will not require the contemporaneous posting of discounted cost-based rates. Finally, commenters have provided no basis to conclude that nonaffiliated buyers are similarly situated whenever a mitigated seller offers an affiliate a discount, and we will not adopt the proposed presumption in this regard. Thus, sellers may selectively discount only if they do so in a manner that is not unduly discriminatory or preferential.

719. Further, we agree with MidAmerican that identifying discriminatory selective discounting requires fact-specific evaluations. Because individual proceedings are the best instrument available to the Commission for such efforts, allegations of undue discrimination arising from selective discounting are best addressed on a case-by-case basis.

3. Protecting Mitigated Markets

a. Must Offer

Commission Proposal

720. Under the Commission's current mitigation policy, a seller that loses market-based rate authority in its home control area is limited to charging cost-based rates in that control area; however, there is no requirement that the seller offer its available power to customers in that home control area. Instead, the seller is free to market all of its available power to purchasers outside that control area if it chooses to do so. If, for example, market prices outside the mitigated seller's control area exceed the cost-based caps within the mitigated control area, then the seller will, other things being equal, have an incentive to sell outside. As noted in the NOPR, wholesale customers have argued that default cost-based mitigation of this kind is of little value if a seller can market its excess capacity at market-based rates in other control areas. In the NOPR, the Commission sought comment on whether its current policy is appropriate, and if not, what further restrictions are needed. The Commission asked whether it should adopt a form of ''must offer'' requirement in mitigated markets to ensure that available capacity (*i.e.*, above that needed to serve firm and native load customers) is not withheld. If so, the Commission asked if such a ''must offer'' requirement should be limited to sales of a certain period to help ensure that wholesale customers use that power to serve their own needs, rather than simply remarketing that power outside the control area and profiting. [790] If it were to adopt such a ''must offer'' requirement, the Commission asked what rules there should be to define the ''available'' capacity that must be offered , in order to avoid case-by-case disputes over this issue.

Comments

721. Wholesale customers generally support a ''must offer'' requirement,'' stating that it is needed to ensure that power is available for purchase in the mitigated market and to protect them from incurring higher costs to serve

[784] *Duke Power,* 113 FERC ¶ 61,192 at P 17 (2005).

[785] 16 U.S.C. 824d(a).

[786] *Public Service Company of Oklahoma,* 54 FERC ¶ 61,021, at 61,032 and fn. 8 (1991) (''If PSO's rates set at full cost are reasonable in the presence of market power, it follows that PSO's rates reflecting less than a 100-percent contribution to fixed costs are also reasonable in the presence of market power.'').

[787] 16 U.S.C. 824d(b).

[788] 16 U.S.C. 824e(a).

[789] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002). Required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001.

[790] In this regard, the Commission asked if there should be an annual open season under which the mitigated seller offers its available capacity to local customers for the following year at the cost-based ceiling rate and, if customers do not commit to purchase that capacity, then the seller would be free to sell the remaining capacity at market-based rates where it has authority to do so.

load.[791] They argue that the existence of a dual price system (a regime where a seller has market-based rate authority in some markets but is limited to cost-based sales in other market(s)) creates an incentive for a mitigated seller to sell its power outside of the mitigated market whenever market prices in the outside market are above the mitigated seller's cost-based price. They are concerned particularly with the situation where a wholesale customer faces few or no alternatives in the mitigated market due to transmission constraints.

722. APPA/TAPS, the Carolina Agencies and NRECA claim that the Commission has both the authority and obligation to remedy undue discrimination in wholesale sales, which are clearly set forth in sections 205 and 206 of the FPA.[792] They specifically argue that a ''must offer'' condition is within the Commission's authority as a remedy for the unjust and unreasonable rates and undue discrimination (refusal to sell in the mitigated control area) that are a consequence of the mitigated seller's accumulation of market power.[793] Several commenters reason that, similar to imposing reporting requirements and other conditions on a grant of market-based rate authority, where a seller no longer has market-based rate authority in its home control area, the Commission may impose a ''must offer'' condition on the continuation of market-based rate authorization outside a mitigated seller's control area.[794] APPA/TAPS and the Carolina Agencies argue that the Commission already imposed a must-offer obligation on the continued availability of market-based rate authority for sellers in the California markets.[795]

723. APPA/TAPS also assert that while Order No. 888 rejected a generic obligation that would have required sellers to continue wholesale sales past the expiration of the contract(s) in question in that proceeding, Order No. 888 explained that the Commission can impose an obligation to continue service on a case-by-case basis.[796]

724. APPA/TAPS and the Carolina Agencies argue that a dominant public utility's physical withholding of generation in the mitigated market in order to make market-based sales elsewhere results in undue discrimination that the Commission has an obligation to remedy. They assert that because wholesale customers in the mitigated market are harmed through decreased supply, increased market concentration, and increased prices, these customers are exposed to the type of injury against which the FPA was designed to protect.[797] The Carolina Agencies also maintain that, whether or not exporting behavior can be considered economically efficient, such behavior results in undue discrimination between (i) The mitigated utility's native load and (ii) LSEs located within the mitigated utility's home control area.[798] This outcome, the Carolina Agencies continue, violates the FPA's mandate that rates be just, reasonable and not unduly discriminatory regardless of whether the mitigated utility's decision to export power is a conscious ''withholding'' for anticompetitive ends.[799] APPA/TAPS and Carolina Agencies add that vertically-integrated utilities with substantial generation in their home control areas frequently have the ability and incentive to discriminate against their wholesale customers, who compete against them on both the wholesale and retail level.[800]

725. APPA/TAPS and Carolina Agencies maintain that undue discrimination occurs if a dominant public utility unjustifiably disadvantages a class of market participants. They cite case law that the D.C. Circuit found ''upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users.'' [801] Absent relevant circumstances that render two sets of customers differently situated, they assert that it is unduly discriminatory for a public utility to sell wholesale power to one set of customers (at market-based rates) while denying service to another set (to whom sales, if made, would need to be priced at cost-based rates). They contend there is no justification for disparate treatment in such a case and, therefore, the Commission is obligated under sections 205 and 206 to remedy such undue discrimination by either denying or conditioning the grant of market-based rate authority outside of the mitigated home control area. A ''must offer'' condition, they claim, would satisfy this obligation by preventing undue discrimination.[802]

726. APPA/TAPS and the Carolina Agencies further allege that, while it may not be unduly discriminatory for a utility to elect to sell to the wholesale

[791] *See, e.g.,* APPA/TAPS at 40–42 (also urging the Commission to apply any ''must offer'' requirement to captive customers in the seller's transmission service area); Carolina Agencies at 10–13; NRECA at 35; Montana Counsel at 19; TDU Systems at 19; NC Towns at 6–8 (asking the Commission to require mitigated utilities to serve wholesale customers in the mitigated control area at long-term system average cost-based rates in order to maintain reliability). *See also* MidAmerican reply comments at 9–12 (arguing that the APPA/TAPS and Carolina Agencies proposals suffer from significant policy flaws).

[792] APPA/TAPS and Carolina Agencies supplemental comments at 4, 9–18 (citing, among others, 16 U.S.C. 824d(a), 824d(b), 824e(a); *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 998 (D.C. Cir. 1987)).

[793] NRECA reply comments at 41 (citing *New York* v. *FERC,* 535 U.S. 1, 27 (2002); *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 683–88 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002)); Carolina Agencies at 4–5; Carolina Agencies reply comments at 2. *See also* Montana Counsel at 19 (citing *Atlantic Ref. Co.* v. *Public Serv. Comm'n of N.Y.,* 360 U.S. 378 (1959) and U*nited Gas Improvement Co.* v. *Callery Properties, Inc.,* 382 U.S. 223 (1965), two cases in which the Montana Counsel claim that the Supreme Court, in recognition of the market power of natural gas producers and the public interest provisions of the NGA, ''virtually ordered'' the Commission to exercise its jurisdiction to condition producer natural gas certificates and rate orders to limit gas prices); APPA/TAPS and Carolina Agencies supplemental comments at 2, 18–30; NRECA supplemental comments at 6–7.

[794] APPA/TAPS at 37–38; APPA/TAPS reply comments at 8; Montana Counsel at 21–22; Carolina Agencies at 4–5; Carolina Agencies reply comments at 3–4.

[795] APPA/TAPS and Carolina Agencies supplemental comments at 27 (citing *San Diego Gas & Elec. Co.* v. *Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal. Ind. Sys. Operator and the Cal. Power Exch.,* 93 FERC ¶ 61,294, at 62,010–11 (2000) (extended-refund-period condition), order *on rehearing and clarification,* 97 FERC 61,275, at 62,243–44 (2001), order *on rehearing and clarification,* 99 FERC ¶ 61,160 (2002), *on rehearing and clarification,* 105 FERC ¶ 61,065 (2003), *petitions for rev. granted in part sub nom. Bonneville Power Auth.* v. *FERC,* 422 F.3d 908 (9th Cir. 2005) and *Public Utils. Comm'n of Cal.* v. *FERC,* 462 F.3d 1027, 1043 (9th Cir. 2006) (discussing must-offer condition)).

[796] APPA/TAPS at 39 (citing Order No. 888—''we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis''); *see also* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,805 & n.652 (1996) (explaining that although the Commission determined ''not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers,'' ''any party claiming to be aggrieved by a utility's alleged abuse of generation market power under a wholesale requirements contract can file a complaint with the Commission under Section 206''); *see also* Montana Counsel at 22.

[797] APPA/TAPS and Carolina Agencies supplemental comments at 19.

[798] Carolina Agencies at 6.

[799] *Id.* at 9.

[800] APPA/TAPS and Carolina Agencies supplemental comments at 16 (citing *FPC* v. *Conway Corp.,* 426 U.S. 271, 278 (1976) to further argue that the Commission can and must take account of competition at retail when determining whether such discrimination exists.)

[801] *Id.* at 13 (citing *Central Iowa Power Coop.* v. *FERC,* 606 F.2d 1156, 1172 (D.C. Cir. 1979); and quoting *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 999 (D.C. Cir. 1987)). APPA/TAPS and Carolina Agencies claim that in this case, a must offer requirement would expand the class of buyers of the mitigated seller's wholesale services to include customers from the mitigated utility's home control area.

[802] *Id.* at 15–16.

customer who will pay the highest price, it is unduly discriminatory if the price differential is based upon mitigation required as a result of the seller's market power.[803] Where sellers claim a right to seek the highest prices, APPA/TAPS and the Carolina Agencies counter that this profit maximization impulse can neither justify the exercise of market power nor insulate it from correction.[804]

727. According to APPA/TAPS and the Carolina Agencies, it is also unduly discriminatory for a mitigated seller to make market-based rate sales outside its home control area when constraints on that entity's own transmission system prevent embedded customers from similarly accessing those markets as buyers. They argue that refusal to sell wholesale power supplies to embedded LSE customers at fully-compensatory cost-based rates effectively compounds the de facto denial of access by exacerbating both the discrimination and the resulting harm.[805] According to APPA/TAPS and the Carolina Agencies, the claim that mitigated sellers are merely engaging in economically efficient behavior ignores the market power that the sellers possess.[806] They state that when captive customers have few or no supply alternatives in the mitigated market and are constrained from accessing opportunities in the broader market (even with open access tariffs), and the dominant supplier sells its excess capacity beyond the mitigated market, the resulting reduction in output in the mitigated market is not addressed simply by prohibiting the mitigated seller from selling at unmitigated prices in the mitigated region.[807] They conclude that it would be unjust and unreasonable to permit or facilitate such withholding by allowing unconditioned sales at market-based rates outside a mitigated supplier's home control area; this would reserve the benefits of competitive markets exclusively to dominant public utility sellers.[808]

728. A number of commenters claim that a ''must offer'' requirement is necessary due to their lack of viable options in mitigated control areas. For example, Fayetteville submits that it finds itself without transmission access to make short-term energy purchases to displace its higher cost generation.[809] Fayetteville contends that Progress Energy's dominant position, as well as Fayetteville's inability to access alternative suppliers due to the inadequacy of Progress Energy's transmission system, gives Progress Energy unmitigated market power.[810]

729. The Carolina Agencies add that, while economic efficiency is a worthy goal in structurally sound markets where participants have ready and equal access to meaningful choices, the idea of economic efficiency cannot justify a mitigated supplier's behavior in a control area where its market power arises from import limitations or other factors that deprive captive LSEs of viable options. Nor can, they claim, the goal of economic efficiency trump the Commission's clear duty to protect customers by ensuring that rates are just, reasonable, and not unduly discriminatory.[811]

730. The Carolina Agencies dispute the claim that there is no need for a ''must offer'' requirement given the Commission's authority to penalize market manipulation. They question whether refusal to sell in the mitigated market would be actionable under the anti-manipulation rules if there is no obligation to offer power to embedded LSEs.[812]

731. NRECA and others ask the Commission to reject the claim that a ''must offer'' requirement would impede a mitigated seller's ability to fulfill its retail crediting obligations.[813] NRECA responds that retail customers can sometimes benefit from cost-based rates; if competition reduces the market price to a seller's marginal cost, no contribution to fixed costs would be recovered. Commenters note that not all utilities are subject to rules requiring the sharing of profits from off-system sales.[814] NRECA argues that a utility's authority to make off-system sales at market-based rates is a privilege granted by the Commission; if the Commission restricts or conditions that privilege, any obligation the public utility has under State law or regulation to sell excess energy or capacity is pre-empted by the requirements of Federal regulation.[815] The Carolina Agencies and NRECA add that a ''must offer'' requirement would serve the intended purpose of the Commission's mitigation policy, which is to protect wholesale customers from the exercise of actual and potential market power, not to preserve a utility's ability to reduce retail rates nor its ability to engage in a certain volume of off-system power sales.[816]

732. NRECA, APPA/TAPS and the Carolina Agencies all set forth proposals in their comments for implementing a ''must offer'' requirement.[817] NRECA suggests requiring a mitigated seller to hold an annual open season to offer long-term service (one year or more), as well as requiring a mitigated seller to offer shorter-term capacity and energy.[818] While not favoring an annual open season, APPA/TAPS and the Carolina Agencies each propose ''must-offer'' parameters to govern short- and long-term sales.[819] For both short- and long-term sales, the Carolina Agencies would offer captive customers an option between (1) Locking-in their price at the mitigated utility's embedded cost rates or (2) agreeing to have their charges determined through an annually updated formula rate that reflects the mitigated utility's actual system-wide average costs.[820] The APPA/TAPS proposal also includes an obligation to offer captive customers participation on proposed generation projects.[821] Both APPA/TAPS and the Carolina Agencies would limit any ''must-offer'' to loads actually located in the mitigated control area.

733. NRECA also proposes two alternatives to a ''must offer'' requirement. First, NRECA suggests that the Commission give captive wholesale customers a right of first refusal to purchase at a market price energy or capacity that the mitigated seller proposes to sell outside the mitigated

[803] *Id.* at 30.

[804] *Id.* at 31.

[805] *Id.* at 30–31.

[806] APPA/TAPS at 6–7; Carolina Agencies reply comments at 6.

[807] APPA/TAPS reply comments at 6–7.

[808] *APPA/TAPS supplemental comments* at 30–31.

[809] Fayetteville reply comments at 5.

[810] *Id.* at 6. *See also* Montana Counsel at 15–23 (where market power is found, sellers should be required to offer power to meet the requirements of dependent customers at cost).

[811] Carolina Agencies reply comments at 9.

[812] Carolina Agencies reply comments at 10–11.

[813] *See, e.g.*, NRECA reply comments at 37–39; Carolina Agencies at 17 (citing April 14 Order, 107 FERC ¶ 61,018 at P 140, 154, where they claim that the Commission rejected arguments that cost-based mitigation rates adversely affect retail rates, because such rates provide for the recovery of the mitigated utility's longer-term costs, and because the adverse impact claims were ''unsupported and speculative.''); Fayetteville reply comments at 7, 9–10.

[814] NRECA reply comments at 38; Carolina Agencies at 8.

[815] NRECA reply comments at 38–39 (citing *Entergy La., Inc.,* v. *La. Pub. Serv. Comm'n*, 539 U.S. 39 (2003); *Miss. Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354 (1988); *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953 (1986)); *see also* Carolina Agencies reply comments at 7–8 (where a utility is satisfying a countervailing regulatory mandate (such as a ''must offer'' obligation, it cannot be held to be violating the cost minimization duty)).

[816] Carolina Agencies at 17; Carolina Agencies reply comments at 7–8; NRECA reply comments at 35.

[817] NRECA at 35; APPA/TAPS at 40–42; Carolina Agencies at 10–13.

[818] NRECA at 35–36.

[819] APPA/TAPS at 40–42; Carolina Agencies at 10–13.

[820] Carolina Agencies at 12–13.

[821] APPA/TAPS at 41.

market.[822] The weakness of this approach, NRECA acknowledges, is that it would allow the mitigated seller to charge wholesale customers a supra-competitive price in the mitigated market given that the market-based rate outside the control area would be higher than the cost-based rate in the seller's control area.[823]

734. NRECA also suggests as an alternative an enforceable commitment to provide sufficient additional transmission import capacity to mitigate the generation market power. It states that such a commitment could be implemented by re-dispatching resources, relinquishing transmission reservations, or physically upgrading the transmission grid. This would allow additional suppliers to make sales in the mitigated region, thereby mitigating the seller's generation market power. NRECA contends that this approach would directly address the larger issue of the need to eliminate transmission bottlenecks and load pockets that give rise to generation market power.[824]

735. The Carolina Agencies also propose that mitigated utilities be required to investigate and report on transmission expansion or other actions that could remove structural impediments causing market power. The Carolina Agencies claim that such a requirement is consistent with the Commission's affirmative duty to remedy undue discrimination, an area in which the Commission has broad authority to craft remedies.[825]

736. Other commenters argue against imposition of a ''must offer'' requirement, stating that it would encourage inefficiencies, undermine competition, discourage investment, and perpetuate market power. They also assert that such a requirement goes beyond any cost-of-service requirement that the Commission has ever adopted.[826] They question the need for a ''must offer'' requirement, claiming that existing Commission statutory authority, regulations, and enforcement mechanisms already sufficiently guard against the market power abuse and market manipulation concerns that ''must offer'' proponents claim such a provision is needed to prevent.[827]

737. EEI and Progress Energy claim that when the Commission establishes a cost-based rate in a mitigated market, it ensures that the rate meets the just and reasonable and not unduly discriminatory requirements of sections 205 and 206 of the FPA, and thus there is no further Commission action that is required to mitigate the indicated market power.[828]

738. Several commenters that argue against imposition of a ''must offer'' requirement state that wholesale customers have not presented sufficient evidence to justify the generic imposition of such a requirement. They state that there have been no specific instances cited where a wholesale customer in a mitigated market was unable to obtain service, much less evidence that such instances are commonplace.

739. Duke/Progress Energy argue that the Commission must make a finding that rates or practices are unjust, unreasonable, or unduly discriminatory as a predicate to taking action, and that in the case of a generic rulemaking, ''the Commission'' cannot rely solely on ''unsupported or abstract allegations.''' [829] They cite *National Fuel Gas Supply Corp.* v. *FERC,*[830] where the D.C. Circuit, describing *Tenneco Gas* v. *FERC,*[831] stated ''[t]he court [in *Tenneco*] 'upheld Order 497 in relevant part because FERC presented an adequate justification—by advancing both (i) A plausible theoretical threat of anti-competitive information-sharing between pipelines and their marketing affiliates and (ii) vast record evidence of abuse.' ''[832] They note that the D.C. Circuit contrasted *Tenneco* with Order No. 2004 (at issue in *National Fuel*), where '' 'FERC has cited no complaints and provided zero evidence of actual abuse between pipelines and their non-marketing affiliates.' '' They assert that the D.C. Circuit concluded that '' '[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decisionmaking.'' '[833]

740. According to Duke/Progress Energy, the commenters favoring a ''must offer'' requirement ''have presented *no evidence whatsoever* to support the conclusion that any systemic discrimination is occurring or that any party is suffering any actual harm under the discrimination theory they have posited.''[834] Duke/Progress Energy offer several examples where they have sold power to LSEs within their control areas after the Commission imposed cost-based mitigation for those sales as evidence that there is no basis for expecting mitigated utilities to abandon long-standing customers and ''decades of intersystem coordination and mutual assistance, whereby utilities take whatever measures are possible * * * to help their neighbors maintain reliability.''[835]

741. A number of commenters assert that the Commission's statutory authority to require wholesale sales under section 202(b) and 202(c) of the FPA is limited and cannot justify the imposition of a ''must offer'' requirement in this context.[836] Southern explains that the Commission has forced power sales by a jurisdictional public utility to wholesale customers under section 202(b) of the FPA only if such customers have proven they lack service alternatives. Southern states that it would be unreasonable to impose a generic obligation to serve at wholesale by means of a ''must offer'' requirement, absent particularized findings based on a properly developed record that wholesale customers lack reasonable alternatives.[837]

742. EEI agrees that the Commission's section 202(b) authority is clearly aimed at individual transactions where a wholesale customer cannot access supply, with ample due process safeguards to ensure that a requirement to sell is truly warranted and will not

[822] NRECA reply comments at 36–37.

[823] NRECA at 36–37. MidAmerican disagrees, arguing that market-based prices are not by definition always higher than cost-based prices in the mitigated region. Rather, the Commission has encouraged open access transmission and market competition because economically efficient market-based rates can be lower than cost-based rates. At the same time, where a price index at a trading hub may be lower than the seller's incremental cost, MidAmerican argues that a seller should never be required to sell at rates below its incremental cost. MidAmerican reply comments at 21.

[824] NRECA at 37.

[825] Carolina Agencies at 16 (citing the OATT Reform NOPR at P 210 and n.203).

[826] *See, e.g.,* Xcel at 5; Progress Energy reply comments at 5. APPA/TAPS and NRECA respond that as long as the rate is cost-compensatory, and therefore just and reasonable, it provides an adequate return and the mitigated supplier is not disadvantaged by making such sale. APPA/TAPS reply comments at 9; NRECA reply comments at 31, 35, 38.

[827] *See, e.g.,* EEI at 36; Progress Energy at 17.

[828] EEI at 37; Progress Energy at 13.

[829] Duke/Progress Energy supplemental coments at 21 (quoting *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 688 (D.C. Cir. 2000) (*TAPS*)).

[830] 468 F.3d 831, 840 (D.C. Cir. 2006) (*National Fuel*).

[831] 969 F.2d 1187 (D.C. Cir. 1992) (*Tenneco*).

[832] Duke/Progress Energy supplemental comments at 22 (quoting *National Fuel,* 468 F.3d at 840).

[833] *National Fuel,* 468 F.3d at 843–44.

[834] Duke/Progress Energy supplemental comments at 23 (citing *TAPS,* 225 F.3d at 688, (emphasis in original)); *see also* Xcel reply comments at 6–7 (parties have not provided any supporting rationale that would justify a ''must offer'' requirement over other potential purchasers); EEI supplemental comments at 3 (commenters have failed to demonstrate that there is discrimination warranting generic action).

[835] Duke/Progress Energy supplemental comments at 17 and n.7.

[836] *See, e.g.,* Pinnacle at 8; EEI at 35–36; Progress Energy reply comments at 5, n.5; Duke reply comments at 6.

[837] Southern at 60.

harm the seller.[838] EEI states that the Commission cannot turn such a provision into a blanket regulatory requirement without violating the intent of Congress and inappropriately bypassing these safeguards, nor is such a blanket requirement warranted.[839]

743. Several commenters question the legal support for a ''must offer'' requirement, arguing that the FPA does not contain an express obligation to serve wholesale customers,[840] and that neither section 205 nor section 206 of the FPA authorize the Commission to mandate or prohibit sales, as long as they are made at just, reasonable, and non-discriminatory rates approved by the Commission.[841]

744. Many commenters also contest claims that sales outside the mitigated control area at market-based rates constitute withholding or undue discrimination. Westar and others suggest that offering generation for sale outside of the mitigated control area at the prevailing market price to serve demand does not constitute withholding. They state that withholding generally refers to either physical withholding (not offering to sell) or economic withholding (offering to sell only at inflated prices), which in either case is intended to raise prices.[842] Duke/Progress Energy claim that ''the Commission has confirmed that it is 'legitimate economically rational' behavior for a market participant to export power in order to sell at higher prices outside a control area rather than to sell at lower capped prices within a control area.'' [843] Westar similarly argues that, absent evidence of manipulation or fraud, a '' 'seller of a commodity is acting quite rationally and legally to withhold his supply from the market if he believes that in the future the commodity will command a higher price—assuming, of course, the seller is under no legal duty to sell.' '' [844] Westar and E.ON U.S. reason that the Commission's market behavior rules already address economic withholding concerns.[845]

745. MidAmerican adds that in the limited instances where a wholesale customer cannot obtain service, and where an obligation to serve exists, the Commission can address the issue in fact-specific proceedings of individual sellers.[846] Duke suggests that the ''must offer'' proponents have failed to demonstrate why ''self-supply,'' including new construction and supply from external resources, is not a viable option in at least some instances.[847] Duke states, for example, that the Carolina Agencies submit that LSEs will have few if any practical supply options if a mitigated supplier is not subject to a must offer requirement. However in Duke's view, the Carolina Agencies fail to demonstrate why ''self-supply,'' including construction of local generation by their members, is not a viable option in at least some instances. Nor do they demonstrate lack of ability to secure supply from resources external to the control area. Duke submits that even where construction of new generation may not be cost-effective, ''self-supply'' includes purchasing as well as self-build. Duke argues that lack of an economic self-build option at a given time does not relieve an LSE of its obligation to acquire generation resources through alternate means such as long-term purchases.[848]

746. Several commenters similarly challenge the claim that choosing to make sales outside the mitigated control area at market-based rates is discriminatory. EEI notes that not all rate distinctions are prohibited by section 205(b) of the FPA. It states that only undue discrimination between customers of the same class that is not justified by cost of service differences, operating conditions, or other considerations is forbidden.[849] In this proceeding, Duke/Progress Energy claim that wholesale customers are seeking a *superior* product to that offered to other customers outside the mitigated control area: ''a Commission-enforced right to a free and unilateral call option to buy any available energy generated by [m]itigated [u]tility assets at cost-based prices, exercisable during peak periods when market prices are high.'' [850]

747. EEI adds that the courts also recognize that the just and reasonable standard allows—and can even require—rate differences to reflect different locations and classes of customers.[851] EEI and Progress Energy therefore contend that, once the Commission has determined whether a seller may sell at market-based rates or must use mitigated rates in various markets, the seller must be allowed to sell electricity at the just and reasonable rates approved for the different markets.[852]

748. MidAmerican claims that customer concerns that a mitigated seller will unduly discriminate between the seller's native load and wholesale customers in the mitigated region are baseless because the Commission's jurisdiction does not extend to a comparison of retail and wholesale rates. MidAmerican states that while a seller typically has an obligation to serve retail customers in a franchised service area, that obligation does not extend to wholesale customers. Therefore, MidAmerican states there is no issue of undue discrimination between retail and wholesale rates that either requires or allows a ''must offer'' requirement.[853]

749. Xcel and others submit that wholesale customers are seeking a preference or entitlement through a ''must offer'' requirement and are in fact calling for discrimination by asserting a preference to power available for sale by a mitigated seller over all other

[838] EEI reply comments at 16.

[839] EEI at 35–36 (citing *El Paso Electric Co.* v. *FERC,* 201 FERC F.3d 667 (5th Cir. 2000)).

[840] MidAmerican at 18–19; EEI at 33; Southern at 59; Westar at 17; Duke at 12; E.ON U.S. reply comments at 1–2; Progress at 13.

[841] EEI at 35; Progress Energy at 13–14; E.ON U.S. reply comments at 1–2; Duke reply comments at 5–6.

[842] EEI reply at 2; Duke/Progress Energy at 15.

[843] Duke/Progress Energy at supplemental comments 16 (quoting *San Diego Gas & Elec. Co.*, 103 FERC ¶ 61,345 at P 63 (2003)).

[844] *See* Westar at 11, n.23 (quoting *United States* v. *Reliant Energy Services Co.*, 420 F. Supp. 2d 1043, 1059 (N.D. Cal. 2006)); *see also* EEI at 36.

[845] Westar at 12; E.ON U.S. reply comments at 7. In adopting those rules, Westar submits that the Commission specifically rejected arguments that ''withholding for an anti-competitive purpose *can only be remedied by way of a generic ''must offer''* obligation,'' stating that ''[i]n fact, where a seller intentionally withholds capacity for the purpose of manipulating market prices, market conditions, or markets rules for electric energy or electricity products, it has done so without a legitimate business purpose in violation of Market Behavior Rule 2.'' Westar at 12 (quoting *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 107 FERC ¶ 61,175 at P 27 (2004) (emphasis added)).

[846] MidAmerican at 19.

[847] Duke reply comments at 10. APPA/TAPS responds that the Commission has recognized that not all LSEs can build their own generation. APPA/TAPS reply comments at 9 (citing April 14 Order, 107 FERC ¶ 61,018 at P 155).

[848] Duke reply comments at 10.

[849] EEI reply comments at 13–14 (citations, including *Wisconsin Michigan Power Co.*, 31 FPC 1445 (1964); *CED Rock Springs LLC*, 116 FERC ¶ 61,163 at P 39 (2006) (In examining potential undue discrimination, the Commission properly focuses on whether ''there are any similarly situated projects that have been treated differently.''); *see also Badger Power Marketing Authority*, 116 FERC ¶ 61,200 at P 10 (2006) (approving a rate that is essentially the same as the rate charged another similarly-situated customer)).

[850] Duke/Progress Energy supplemental comments at 9.

[851] EEI reply comments at 14–15 (citing *Town of Norwood, Massachusetts* v. *FERC*, 202 F.3d 392 at 402 (1st Cir. 2000) (''[D]ifferential treatment does not necessarily amount to undue preference where the difference in treatment can be explained by some factor deemed acceptable by the regulators (and the courts).''); *City of Vernon, California* v. *FERC*, 983 F.2d 1089 at 1093 (D.C. Cir. 1993)).

[852] *Id.* at 15; Progress Energy at 13.

[853] MidAmerican reply comments at 7; *see also*, Duke reply comments at 6. *Compare* APPA/TAPS reply comments at 3 (''The Commission is not called upon to decide a struggle between wholesale and retail ratepayers, but to set a just and reasonable wholesale rate, which a Commission-approved cost-based rate surely is.'').

purchasers, even those who value it more highly,[854] and have provided no evidence to justify such a preference or entitlement over other potential purchasers.[855] Duke/Progress Energy state that customer claims that ''they are victims of market power and therefore need some specially tailored remedy'' is erroneous, and that ''[b]y imposing cost-based rates * * * within their control area, the Commission has fully mitigated any market power concerns.'' [856] Xcel and others also note that the LSEs have no reciprocal obligation to purchase power if a ''must offer'' requirement were imposed upon mitigated sellers.[857]

750. According to Duke and others, when a mitigated supplier sells excess generation at market-based rates outside of the mitigated control area, it is exhibiting economic behavior.[858] Such behavior encourages trading within and across regions, making markets more competitive. Similarly, Westar contends that a ''must offer'' requirement prevents markets from allocating scarce resources to customers who value them the most, hindering optimal resource allocation.[859] Westar states that this is inefficient because ''the highest cost generation may not be displaced by the seller's lower cost energy.'' [860]

751. EEI, Progress Energy, and others also claim that a ''must offer'' requirement would effectively take economic benefits away from the mitigated utility's retail native load and transfer them to wholesale customers in the mitigated control area.[861] Some of these commenters claim that a ''must offer'' requirement may result in a windfall for the wholesale customer originally seeking protection from the seller's market power at the expense of the mitigated utility and its native load customers.[862] PNM/Tucson adds that sales made by a utility pursuant to a ''must offer'' requirement could affect reliability by making capacity unavailable to meet State-established reserve margins.[863]

752. Xcel and Duke point out that a ''must offer'' requirement at cost-based rates may result in a lost opportunity cost to the seller.[864] A number of commenters assert that mitigation is intended to assure that selling utilities do not benefit from the exercise of market power; it is not to guarantee preferential treatment for particular customers to obtain below-market generation through an obligation to serve.[865]

753. Some commenters further contend that a ''must offer'' requirement would create significant wealth transfers from mitigated sellers as a result of arbitrage opportunities. For example, wholesale customers would accept the mitigated offer any time the ''must offer'' price was below the market price, either in or outside of the mitigated region.[866] E.ON U.S. is concerned that a ''must offer'' requirement giving a buyer the option to buy power at mitigated prices will inevitably result in external third parties negotiating with such a buyer to obtain longer-term access to the mitigated power.[867]

754. In addition, EEI and others argue that a ''must offer'' requirement would reduce competition and stifle development by providing a disincentive for sellers to develop new generation resources.[868] New entrants would be deterred from building generation due to the disparity between cost-based and market-based rates;[869] other sellers in the mitigated region effectively would be mitigated because they would not be selected by buyers unless their price is below the mitigated price of the ''must offer'' requirement.[870] At the same time, EEI asserts that the mitigated seller would perpetuate its market power by increasing its capacity in the mitigated control area.[871]

755. Progress Energy and MidAmerican add that a ''must offer'' requirement would impede a mitigated seller's ability to fulfill its retail crediting obligations and to provide adequate and reliable service to its native load retail customers, which bear, through their retail rates, the fixed costs of the generation to serve them.[872]

756. Southern, Duke and others further suggest that a ''must offer'' requirement could undermine the required planning and operations processes of utility systems purchasing the ''must offer'' output.[873] They argue that a ''must offer'' requirement could bias shorter-term operating decisions where, for example, an LSE has the opportunity to purchase peak supply in real time at less than market prices, thereby avoiding incurring any fixed costs on a day-ahead basis to ensure peak supply availability.[874] They contend that this would eliminate incentives for the LSEs to plan to meet their resource needs and shift planning obligations at the expense of a mitigated utility's native load customers.[875]

757. Another commenter is also wary of a ''must offer'' requirement, reasoning that such a requirement is normally designed to mitigate physical withholding. This commenter states that it may work well in an organized power market where an independent operator ensures that the power is used to serve the local needs caused by reliability or local resource deficiency. However, without an independent operator, a ''must offer'' requirement may be more difficult to administer.[876] In advocating for separate market policies and tests for short- and long-term markets, this commenter prefers a price cap for short-term products rather than a ''must offer'' requirement, asserting that a price cap for short-term products is preferable to a ''must offer'' approach because it is more economically efficient, fair, and easier to administer.[877] For long-term products, this commenter takes the position that, ''[i]n situations where a lack of long-term transmission and/or a lack of long-term supply alternatives exist, it is difficult to think of an

[854] Xcel reply at 6–7; EEI supplemental comments at 4–5.

[855] Xcel reply comments at 6–7; Progress Energy reply comments at 2, 4, 7–11; Duke reply comments at 7, n.10.

[856] Duke/Progress Energy supplemental comments at 13 (citing *Duke Power*, 113 FERC ¶ 61,192 at P 22).

[857] Xcel reply comments at 7; Progress Energy reply comments at 6; MidAmerican reply comments at 9.

[858] Duke at 11; Xcel at 6; Southern at 56–57; EEI reply comments at 11.

[859] Westar at 13 (citing *Pacific Gas and Electric Company,* 38 FERC ¶ 61,242 at 61,790 (1987)).

[860] *Id.* (quoting *Pacific Gas and Electric Company,* 38 FERC at 61,790, n.19).

[861] *See, e.g.*, EEI at 33; Progress Energy at 14, 16; Entergy at 2; Westar at 16; *see also* Dr. Pace at 24–25.

[862] PPL reply comments at 14; Duke reply comments at 2, 7–8; Progress Energy at 16; E.ON U.S. at 13–14; Duke at 12–13; MidAmerican at 27.

[863] PNM/Tucson at 18.

[864] Xcel at 8; Duke reply comments at 3, n.4.

[865] Xcel at 5; EEI reply comments at 10, 12; Progress Energy at 14.

[866] Progress Energy at 16; Westar at 16.

[867] E.ON U.S. at 13.

[868] EEI at 37; Progress Energy at 16; MidAmerican at 22. APPA/TAPS responds that it is in fact the mitigated seller's constrained transmission system that keeps LSEs captive and prevents new entry that could reduce the seller's market power. APPA/TAPS reply comments at 9.

[869] EEI reply comments at 10.

[870] MidAmerican reply comments at 8.

[871] EEI reply comments at 10.

[872] *See, e.g.*, Progress Energy at 14–15; E.ON U.S. at 12–13; PNM Tucson at 18; MidAmerican at 21.

[873] Southern at 61; Progress Energy at 16; Duke reply comments at 9–10; EEI reply comments at 10–11.

[874] Southern at 63.

[875] Duke reply comments at 8–11. APPA/TAPS counters that where a ''must offer'' requirement would not, by its own terms, obligate a seller to build, an LSE that relied exclusively on ''must offer'' sales would be taking risks that capacity to support those sales might no longer be available. APPA/TAPS reply comments at 9.

[876] Drs. Broehm and Fox-Penner at 16–17.

[877] Drs. Broehm and Fox-Penner supplemental comments at 3. Drs. Broehm and Fox-Penner advocate other approaches, such as use of a proxy price when transmission constraints are not binding and use of default cost-based rates when they are binding.

alternative to full cost-of-service rates.'' [878] They add that these cost-based rates should offer both fair prices and adequate investment returns to suppliers in the destination market with rate-of-return levels that fully enable incumbent suppliers to make appropriate investments to meet such cost-based obligations.[879]

758. Entergy raises a concern that in the NOPR the Commission erred by failing to define what constitutes available capacity. It asserts that there is difficulty in calculating available capacity because of uncertainty regarding: (1) Loads; (2) qualifying facility puts; (3) unit performance; and (4) fuel arrangements and prices.[880]

Commission Determination

759. After careful consideration of the arguments raised by commenters, we will not impose an across-the-board ''must offer'' requirement for mitigated sellers. While wholesale customer commenters have raised concerns relating to their ability to access needed power, we conclude that there is insufficient record evidence to support instituting a generic ''must offer'' requirement.

760. As discussed above, some commenters argue that undue discrimination occurs if a mitigated seller refuses to sell power to customers in the mitigated balancing authority area and instead sells that power at market-based rates to customers outside the mitigated balancing authority area. Some commenters also contend that it is unduly discriminatory for a mitigated seller to make market-based rate sales to competitive markets outside the mitigated balancing authority area when constraints on that seller's own transmission system prevent embedded customers from similarly accessing those markets as buyers. However, these commenters have not provided any evidence of specific instances in which the harms they identify have, or are, occurring. Without such evidence, we decline to impose a generic remedy such as a ''must offer'' requirement.

761. In *National Fuel*, the D.C. Circuit vacated a final rule of the Commission, Order No. 2004, as applicable to natural gas pipelines because of the expansion of the standards of conduct to include a new definition of energy affiliates. The court explained that the Commission relied on both theoretical grounds and on record evidence to justify this expansion. The court concluded that the Commission's record evidence did not withstand scrutiny and, thus, concluded the expansion was arbitrary and capricious in violation of the Administrative Procedure Act.[881] While the court left open the possibility of the Commission relying solely on a theoretical threat of abuse, it cautioned that if the Commission chooses to take that approach, ''it will need to explain how the potential danger * * * unsupported by a record of abuse, justifies such costly prophylactic rules.'' [882] In addition, the court said the Commission would need to explain why individual complaint procedures were insufficient to ensure against abuse.[883]

762. We find here that, although wholesale customer commenters have raised theoretical concerns that they will be unable to access power absent a ''must offer'' requirement, they have not provided any concrete examples of harm nor explained how the potential harm justifies the generic remedy they seek. Given the lack of evidence in the record that wholesale customers in mitigated markets will be unable to obtain power supplies at reasonable rates, we conclude that there is insufficient basis for instituting a generic ''must offer'' requirement. Indeed, the record includes evidence of utilities continuing to make cost-based sales after loss or surrender of market-based rate authority.[884]

763. In addition, consistent with the guidance provided in *National Fuel,* commenters advocating a generic ''must offer'' have not demonstrated that existing procedures and remedies under the FPA are inadequate to deal with specific cases that may arise. To the contrary, we find that there are potential remedies available on a case-by-case basis to a wholesale customer alleging undue discrimination or other unlawful behavior on the part of a mitigated seller. For example, a wholesale customer can file a complaint pursuant to section 206 of the FPA. It also can bring an action under section 202(b) of the FPA.[885] In addition, it can bring an action pursuant to the statutory prohibition in section 222 of the FPA against market manipulation.

764. While we do not impose a generic ''must offer'' requirement in this Final Rule, we do not rule out the possibility that we might find the imposition of a ''must offer'' requirement, or some other condition on the seller's market-based rate authority, to be an appropriate remedy in a particular case depending on the facts and circumstances, as we have done in the past.[886] We note that the Commission has previously imposed a ''must offer'' requirement as a condition of market-based rate authority for sellers in the California markets.[887] There, the record demonstrated a problem in a limited geographic area that warranted a ''must offer'' remedy to prevent unjust and unreasonable rates from being charged during certain times and under certain conditions. If a wholesale customer were to present specific evidence documenting that a transmission provider either denied the customer's request for transmission service, in violation of the OATT, or was unreasonably delaying responding to a request for transmission service, in violation of the OATT, we might find the imposition of a ''must offer'' requirement on a transmission provider to be an appropriate remedy.[888] As the Commission recently explained in Order No. 890, transmission providers must process requests for transmission service ''as soon as reasonably practicable after receipt'' of such requests [889] and must post performance metrics that are intended ''to enhance the transparency of the study process and shed light on whether transmission providers are processing request studies in a non-discriminatory manner.'' [890] Order No. 890 explained that ''the revised *pro forma* OATT will greatly enhance our oversight and enforcement capabilities by increasing the transparency of many critical functions

[878] *Id.*

[879] *Id.*

[880] Entergy at 2–3.

[881] *National Fuel,* 468 F.3d at 844.

[882] *Id.*

[883] *Id.*

[884] *See* Duke reply comments at 7 and n.10; Progress Energy reply comments at 9–11; Duke/Progress Energy supplemental comments at 17 and n.7.

[885] *See, e.g, City of Las Cruces, New Mexico* v. *El Paso Electric Co.,* 87 FERC ¶ 61,220 (1999) (''In our view, section 202(b) allows the Commission to direct a public utility to take three separate actions: (1) Establish a physical connection of its transmission facilities with the facilities of one or more eligible persons; (2) sell energy to eligible persons; or (3) exchange energy with eligible persons.'')

[886] If an intervenor believes a ''must-offer'' requirement is the only way to mitigate market power, it may present evidence to that effect in a particular proceeding.

[887] S*ee San Diego Gas & Elec. Co.,* 95 FERC ¶ 61,418 at 62,557 (2001) (''After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged and could continue to be charged during certain times and under certain conditions, unless certain targeted remedies were implemented.'')

[888] We are not prejudging here that such facts warrant imposition of a ''must offer'' requirement.

[889] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1296 (2007) (Order No. 890).

[890] *Id.* at P 1308.

under the *pro forma* OATT, such as ATC calculation and transmission planning.'' [891] Here too, we reiterate that the Commission ''intends to use its enforcement powers with respect to the OATT in a fair and even-handed manner, pursuant to the principles set forth in the Policy Statement on Enforcement.'' [892]

765. In addition to our conclusion that there is not sufficient record evidence to support the imposition of a generic ''must offer'' requirement, we are also concerned that adoption of a ''must offer'' requirement would present a number of difficult implementation and logistical problems.[893]

766. For example, given the difficulties associated with calculations of available transfer capability,[894] we foresee similar disputes over the calculation of available generation capacity were we to impose a generic ''must offer'' obligation. For instance, how far in advance should such calculations occur—one hour, one day, one month, or some other time frame? Would such calculations be derived on a generator specific basis or on a system basis (and how is transmission factored in)? Would the Commission or the industry need to develop a standard method of calculating available generation capacity? How would available generation capacity be allocated to potential purchasers?

767. We also are concerned that adopting a ''must offer'' requirement could harm other markets. For example, if a mitigated seller is required to offer its available power first to customers in the mitigated market, such a requirement may effectively preclude the mitigated seller from participating in adjoining markets particularly at times when additional supply is most needed (*i.e.*, when prices in the adjoining market are high). Such a policy may serve to assist one set of customers at the expense of other customers that see their supply options reduced.

768. Parties have asserted that imposing a must offer requirement may discourage long-term planning, while others have disagreed with those arguments. Given that we do not impose any must offer obligation in this rule, we need not and do not address these arguments. If the Commission considers imposing a ''must offer'' requirement in an individual case, affected parties can raise these arguments at that time.

769. Though APPA/TAPS and the Carolina Agencies are correct that the Commission has previously imposed a ''must offer'' requirement as a condition of market-based rate authority for sellers in the California markets, as discussed above, that holding supports our approach here. There, the record demonstrated a problem in a limited geographic area that warranted a ''must offer'' remedy to prevent unjust and unreasonable rates from being charged during certain times and under certain conditions. By contrast, here APPA/TAPS and the Carolina Agencies urge us to impose a generic remedy on all mitigated sellers in all markets without a showing that there is a concrete problem justifying imposition of a ''must offer'' requirement in all markets.

770. Given that we have not adopted a ''must offer'' requirement in this Final Rule, we need not, and do not, address arguments asserting that we lack legal authority to do so. If the Commission should adopt any such requirement in an individual case, affected parties can raise any related legal arguments at that time and nothing in this rule precludes them from doing so.

771. For many of the same reasons that we decline to impose a ''must offer'' requirement, we also decline to adopt the ''right of first refusal'' requirement proposed by NRECA. Under this approach, a wholesale customer in the mitigated market would be given a right of refusal to purchase, at the market price, power that the mitigated seller proposes to sell outside the mitigated market. For the reasons provided above, there is insufficient record evidence to support imposition of such an across-the-board requirement.

772. A ''right of first refusal'' also would carry significant administrative burdens. Such an approach would invite disputes about what constitutes a legitimate offer by a third party to purchase power which establishes the basis for the offered rate. There also may be disputes if more than one wholesale customer wants to purchase the power in question. We are also concerned about the long-term viability of a rate setting that is based on mitigated sellers repeatedly negotiating tentative power sale arrangements with would-be buyers in first-tier markets only to have those offers withdrawn so the sale could be made to another buyer. Under such a regime, buyers from outside the mitigated market may be disinclined to invest resources to negotiate tentative contracts knowing that there is a significant chance that another buyer from within the mitigated market will usurp their position and instead get the sale.

773. There are also administrative concerns with how the Commission or third parties could be certain what the actual price and conditions of service would be for the sale in the first-tier market unless the contract was actually executed.

774. In response to NRECA's suggestion that an enforceable commitment to provide sufficient additional transmission import capacity to mitigate generation market power be considered as an alternative, the Commission notes that, consistent with the April 14 Order, a seller that fails one of the generation market power screens is allowed to propose alternative mitigation that the Commission may deem appropriate.[895] As a result, a mitigated seller could propose, as alternative mitigation, to provide additional transmission capacity by, for example, committing to relinquish transmission reservations or to physically upgrade the transmission grid.[896] The Commission would consider such proposals on a case-by-case basis. Moreover, a primary purpose of Order No. 890 is to ''increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process.'' [897]

775. In particular, we believe recent actions we took in Order No. 890 address the Carolina Agencies' proposal that mitigated utilities be required to investigate and report on transmission expansion or other actions that could remove structural impediments exacerbating market power. In Order No. 890, the Commission adopted a number of reforms designed to mitigate transmission market power, including a requirement that all transmission providers develop a coordinated, open and transparent transmission planning process that would, among other things, enable customers to request studies evaluating potential upgrades or other investments that could reduce congestion or integrate new resources and loads.[898] The requests for these

[891] *Id.* at P 1721.

[892] *Id.* at P 1714.

[893] Because we have decided not to impose a generic ''must offer'' requirement in this Final Rule, we do not address the merits of the particular must-offer proposals made by commenters.

[894] OATT Reform NOPR at PP 37–41 (outlining problems that result from inconsistent available transfer capacity calculation, including missed opportunities for transactions, frequent errors, and undue discrimination).

[895] April 14 Order, 107 FERC ¶ 61,018 at P 147, 148 n.142.

[896] *See, e.g., Westar Energy, Inc.,* 115 FERC ¶ 61,228, *order on reh'g,* 117 FERC ¶ 61,011 (2006), *order on further reh'g,* 118 FERC ¶ 61,237 (2007) (concerning such mitigation proposed in the context of a disposition of jurisdictional facilities).

[897] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 3.

[898] *Id.* at P 544.

economic planning studies and the responses will be posted on the transmission provider's OASIS site, subject to confidentiality requirements.[899] We believe these steps may assist in reducing structural impediments that contribute to market power.

b. First-Tier Markets

Commission Proposal

776. In the NOPR, the Commission sought comment on whether it is appropriate to continue to allow sellers that are subject to mitigation in their home control area to sell power at market-based rates outside their control area. The Commission asked if this represents undue discrimination or otherwise constitutes ''withholding'' in the home control area that is inconsistent with the FPA's mandate that rates be just, reasonable and not unduly discriminatory, or, instead, if this reflects economically efficient behavior and encourages necessary trading within and across regions, particularly in peak periods when marginal prices rise above average embedded costs.

777. The Commission also asked if it should find that any seller that has lost market-based rate authority in its home control area should be precluded from selling power at market-based rates in adjacent (first tier) control areas.

Comments

778. A number of commenters state that there is no basis for prohibiting a mitigated seller from selling excess power at market-based rates in adjacent control areas, as the Commission will have determined that the seller does not have the ability to exercise market power in any of those adjacent control areas.[900] Some commenters also claim that prohibiting these sales would limit market activity and constrain the benefits of competitive pricing by excluding sellers from markets in which they do not possess market power.[901]

779. PNM/Tucson contends that prohibiting sales of available capacity at market-based rates in adjacent control areas where the seller does not possess market power would be a disproportionate response that would render the Commission's market-by-market analysis meaningless.[902] Moreover, PNM/Tucson and MidAmerican warn that independent power producers have no incentive to invest in new resources in markets where prices are effectively constrained to the level of another entity's embedded costs.[903]

780. Southern asks the Commission not to impose mitigation that will create flaws in markets that may have periods of genuine temporary scarcity but where the seller does not possess market power.[904] Southern states that prohibiting a mitigated seller from responding to price signals in neighboring markets will adversely affect efficient resource development and contradicts the Commission's desire to promote competitive markets and resource adequacy.[905] Further, foreclosing markets otherwise accessible to resources nominally dedicated to native load service may impair the optimization of those resources by impairing a full response to price signals. This, Southern adds, would harm native load customers because the mitigated utility would be unable to optimize surplus resources, as mandated through State retail credit obligations, thereby depriving retail customers of the benefits of system optimization.[906]

781. Another commenter agrees that a mitigated seller should be allowed to sell available capacity at market-based rates in markets where that seller does not possess market power, provided that this does not raise prices in the mitigated region.[907] This commenter asserts that such sales facilitate regional trading and market efficiency in developing competitive markets.[908] Another commenter contends that unless ''costs'' are defined in a way that effectively allows competitive market rates to be charged, revoking a seller's market-based rate authority in markets where the seller does not possess market power would reduce the mitigated seller's incentive to supply available power to the market, deprive the mitigated seller and its customers of legitimate economic rent, subsidize those buyers with access to the mitigated rates, and create a rationing problem among buyers with access to the mitigated-rate power.[909]

782. MidAmerican states that, if the Commission were to eliminate a seller's market-based rate authority in all regions, the mitigated prices should only apply prospectively. MidAmerican reasons that existing transactions negotiated in the absence of market power should not be altered, since these previously-negotiated transactions would have no impact on a seller's willingness to make future sales to customers in the home control area.[910]

783. Other commenters oppose allowing mitigated sellers to sell at market-based rates outside the home control area on the basis that it encourages and provides incentives for the seller to engage in physical or economic withholding of its generation output in the home control area. These commenters indicate that their concerns in this regard would be addressed if mitigation is combined with a requirement that the mitigated seller make power available to customers within the mitigated control area. APPA/TAPS state that, absent a ''must offer'' requirement, it is not clear that prohibiting mitigated sellers from making market-based sales outside their home control areas would necessarily prompt the mitigated seller to sell power in its home control area.[911]

784. However, APPA/TAPS ask the Commission not to rule out across-the-board revocation of market-based rate authority as it may be necessary to motivate mitigated sellers to undertake the kind of structural measures needed to mitigate market power on a long-term basis. If the Commission adopts a policy to revoke or condition market-based rate authority beyond the home control area, APPA/TAPS state that the policy should not be limited to just the first-tier control area. Rather, the revocation or conditions should apply to any market where the seller can use generation located in or originally delivered to its control area to sell outside that mitigated area.[912]

785. The Carolina Agencies state that a generic prohibition on market-based rate sales outside the mitigated market

[899] *Id.* at P 546 (to be codified at 18 CFR 37.6(b)(2)(iii)).

[900] Ameren at 18–19; *see also* Duke at 12 (citing *Florida Power Corp.,* 113 FERC ¶ 61,131 at P 24 (2005)); Southern at 56; PNM/Tucson at 19–20 ; Xcel at 5–6; EEI at 33; and PPL reply comments at 15–16.

[901] MidAmerican at 22–23; PPL at 24–25; EEI at 28.

[902] PNM/Tucson at 19–20.

[903] MidAmerican at 22, PNM/Tucson at 17.

[904] Southern at 64–65.

[905] *Id.* at 57.

[906] *Id.*

[907] Drs. Broehm and Fox-Penner at 16. The NYISO also supports market-based rate sales in competitive markets where the mitigated seller does not possess market power. According to the NYISO, with regard to the NYISO, PJM Interconnection, LLC and ISO-New England, the Commission can ensure that sellers respond to market price signals by designing market power mitigation in a manner that will permit even mitigated sellers to receive the applicable market clearing price. For example, any cost-based rate mitigation imposed could limit the maximum bids that the seller may submit without limiting the revenues that the mitigated seller may receive. NYISO at 10.

[908] Drs. Broehm and Fox-Penner at 16. *See also* PPL at 24; MidAmerican at 17; E.ON U.S. at 12–13; EEI at 28; Duke at 11.

[909] Dr. Pace at 21.

[910] MidAmerican at 23.

[911] APPA/TAPS at 43.

[912] APPA/TAPS at 43–44.

appears likely to inhibit regional trade to a greater extent than is necessary to protect the interests of embedded LSEs.[913] Both the Carolina Agencies and NC Towns state that there is no clear need to prohibit mitigated sellers from making market-based sales outside their home control areas if a ''must offer'' requirement is adopted.[914] According to the Carolina Agencies, a mitigated seller should be free to engage in market-based rate sales in other control areas as long as that utility has provided embedded LSEs a reasonable opportunity to purchase capacity and/or energy.

786. As to any claim that it would be unduly discriminatory for the Commission to deny or condition the market-based rate authority of a utility that passes the screens in markets beyond its mitigated home control area, APPA/TAPS and the Carolina Agencies submit that mitigated sellers are not similarly-situated to the other utilities selling at market-based rates in those other competitive markets. They assert that other sellers' market-based rate sales do not implicate those sellers' ability to withhold supply from disfavored wholesale customers in a mitigated control area. Moreover, they argue that it elevates the importance of the screens above the FPA to argue that granting unconditioned market-based rate authority to one seller who passes the screens obligates the Commission to grant unconditioned authority to all who pass the screens. In their view, the Commission would be failing its duty under the FPA if it permitted physical withholding by a dominant utility, as such actions would be unjust, unreasonable, and unduly discriminatory.[915]

787. ELCON advocates suspending any mitigated seller's market-based rates in all markets it can access. Short of this long-term fix, ELCON asserts that other proposals such as ''must offer'' requirements will be prone to fail because of likely unintended consequences.[916]

788. Morgan Stanley favors requiring mitigated sellers to post the mitigated price and other material terms on a publicly-available Web site for all sales to be made from the units that are part of the portfolio covered by the Commission's market power finding, regardless of where the actual sale sinks.[917] Morgan Stanley asserts that effective mitigation can only occur if it is imposed on all sales from a mitigated supplier's generation portfolio and urges the Commission not to focus on who the purchaser is or where the power sinks.[918] If a mitigated seller chooses to offer its excess power only outside the mitigated region and simply refuses to sell inside its home market, Morgan Stanley is concerned that the market in the ''home'' territory would be even less competitive than if the seller were allowed to sell there on an unmitigated basis.[919]

789. CAISO states that, where a competitive supply of imports into a mitigated control area does not exist, market power mitigation mechanisms or other incentive schemes will be necessary to ensure that the local supplier makes all of its capacity available to supply energy and ancillary services to the home control area.[920] CAISO asks the Commission to provide greater clarity on the extent to which the antifraud and anti-manipulation rules adopted in Order No. 670 prohibit economic and physical withholding of resources. In particular, CAISO asks the Commission to provide greater clarity on the deceptive conduct criteria it would use to determine whether a particular case of physical or economic withholding would be a violation of the new Part 47 regulations. CAISO explains that greater clarity in this area will help ISO and RTO market monitors in developing effective RTO/ISO market power mitigation rules tailored for the types of physical and economic withholding that are not addressed under Part 47 regulations.

Commission Determination

790. After careful consideration of the arguments raised by commenters, we will retain our current policy and limit mitigation to the market in which the seller has been found to possess, or chosen not to rebut the presumption of, market power. We will not place limitations on a mitigated seller's ability to sell at market-based rates in balancing authority areas in which the seller has not been found to have market power.

791. The Commission authorizes sales of electric energy at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power in generation and transmission, and cannot erect other barriers to entry. As the Commission has explained, ''The consideration of market power is important in determining if customers have genuine alternatives to buying the seller's product.'' [921] Commenters favoring revocation of a mitigated seller's market-based rate authority in markets where there has been no finding of market power, as well as those supporting broadening mitigation to first-tier markets, have not provided a sufficient legal basis for such a policy. Where the record demonstrates that a seller does not have market power in a market, or has adequately mitigated any market power, the Commission has authorized such a seller to transact under market-based rates.[922] As the April 14 Order explained, ''Market-based rates will not be revoked and cost-based rates will not be imposed until there has been a Commission order making a definitive finding that the applicant has market power * * *'' [923]

792. We recognize that wholesale customer commenters are generally concerned that allowing mitigated sellers to sell outside their mitigated markets at market-based rates could encourage such sellers not to offer generation for sale within the mitigated market. However, we agree with the Carolina Agencies that a generic prohibition against such sales could inhibit regional trade to a greater extent than necessary to protect captive LSEs. We note that even some wholesale customer commenters acknowledge that it is not clear that prohibiting mitigated sellers from making market-based sales beyond their mitigated region would prompt the mitigated seller to sell power in the mitigated market. For these reasons, we limit mitigation to the areas in which the seller has market power.

793. For the reasons stated above, we disagree with Morgan Stanley's assertion that effective mitigation can only occur if it is imposed on all sales from a mitigated seller's generation portfolio. In addition, though we appreciate CAISO's request for greater clarity on the criteria the Commission

[913] Carolina Agencies at 19.

[914] *Id.* at 18–19; NC Towns at 7.

[915] APPA/TAPS and Carolina Agencies supplemental comments at 36–37. NRECA adds that ''the FPA does not bar—as unduly discriminatory—Commission imposition of remedies in a non-discriminatory fashion, including banning sales outside the mitigated market: the statute protects buyers, not sellers, from undue discrimination.'' NRECA reply comments at 41; *see also* Carolina Agencies at 16 (citing the OATT Reform NOPR at P 210 and n.203).

[916] ELCON at 11.

[917] Morgan Stanley at 7; Morgan Stanley reply comments at 6.

[918] Morgan Stanley reply comments at 6. The Oregon Commission responds that such broad mitigation would not benefit wholesale customers in the mitigated region and would harm the supplier's native retail load by transferring wealth to marketers like Morgan Stanley. Oregon Commission reply comments at 4; *see also* MidAmerican reply comments at 13–14 (arguing that Morgan Stanley's proposal would be an arbitrary and capricious redistribution of income and allow windfall arbitrage profits).

[919] Morgan Stanley at 6.

[920] CAISO at 16.

[921] *Louisville Gas & Elec. Co.,* 62 FERC at 61,144.

[922] *Florida Power Corp.,* 113 FERC ¶ 61,131 at P 24.

[923] April 14 Order, 107 FERC ¶ 61.018 at P 149.

will use to determine whether economic and physical withholding has occurred, such a determination must be made on a case-by-case basis.

c. Sales That Sink in Unmitigated Markets

Commission Proposal

794. In the NOPR, the Commission stated that some companies have proposed limiting mitigation to sales that ''sink in'' the mitigated market, that is, so that mitigation would only apply to end users in the mitigated market. However, in *MidAmerican Energy Company,*[924] the Commission stated that limiting mitigation to sales that ''sink in'' the mitigated market would improperly limit mitigation to certain sales, namely, only to sales to buyers that serve end-use customers in the mitigated market. The Commission reasoned that limiting mitigation in this manner would improperly allow market-based rate sales within the mitigated market to entities that do not serve end-use customers in the mitigated market.[925] The Commission stated that such a limitation would not mitigate the seller's ability to attempt to exercise market power over sales in the mitigated market and is inconsistent with the Commission's direction in the April 14 and July 8 Orders. On rehearing of the April 14 Order, it was argued that access to power sold under mitigated prices should be restricted to buyers serving end-use customers within the relevant geographic market in which the seller has been found to have market power. In particular, arguments were made that a seller should not be required to make sales at mitigated prices to power marketers or brokers without end-use customers in the relevant market. In the July 8 Order, the Commission rejected the suggestion that mitigated sellers be restricted to selling power only to buyers serving end-use customers, and has since rejected tariff language that proposes to do so.

795. In the NOPR, the Commission sought comment on whether it should modify or revise its current policy. The Commission sought comment on whether and, if so, how it should allow market-based rate sales by a mitigated seller within a mitigated market if those sales do not ''sink'' in that control area.

Comments

796. While some commenters generally seek to allow a mitigated seller to make sales at market-based rates if those sales do not ''sink'' in the mitigated market, other commenters support the current policy of requiring all of a mitigated supplier's sales in the mitigated market to be cost-based. The State AGs and Advocates go even further and encourage the Commission to apply its mitigation policy to all wholesale sales that sink in the mitigated market, regardless of the seller, arguing that the impact of market power on price is market-wide in scope.[926]

797. APPA/TAPS support the current policy of requiring cost-based rate mitigation for all sales in the mitigated market regardless of whether the sales ultimately sink in an unmitigated market. APPA/TAPS argue that allowing market-based rate sales in a mitigated market would yield unlawful rates because the mitigated seller would be making market-based rate sales in a market where it has, or is presumed to have, market power.[927]

798. The NYISO agrees that mitigation should not be limited to sales that ''sink in'' the mitigated market, at least in clearing price auctions such as those administered by the NYISO. The clearing prices are established by the interaction of all eligible buyers and sellers, and the NYISO reasons that there would be no practical basis, nor economic justification, for carving out marketers or brokers who may export their purchases.[928]

799. The Carolina Agencies express concern that limiting mitigation to sales that sink in a mitigated market would reduce supply options for LSEs embedded in that mitigated market. They contend that unrestricted exports from a mitigated market increase the prices charged by other sellers due to scarcity. Even when a sale sinks outside the mitigated market, the Carolina Agencies claim that round-trip gaming will continue, and they question the Commission's ability to effectively detect and stop such gaming by attempting to trace megawatts via NERC tag data or other means. However, the Carolina Agencies submit that with a properly structured ''must offer'' requirement in place, there is no reason to bar market-based rate sales based on the location of the point of sale or even the identified sink.[929]

800. Other commenters support allowing sales of power within a mitigated market that nonetheless sink in unmitigated markets (*i.e.*, markets where the seller does not possess market power) to be made at market-based rates.[930] As discussed below, they offer various proposals on what factors should determine whether a sale should be priced at market-based rates.

801. Several commenters state that the relevant inquiry should be whether the power serves load (sinks) in a control area where generation market power is an issue. MidAmerican and the Oregon Commission submit that there is no reason to mitigate sales over which the seller is unable to exercise market power.[931] Rather, MidAmerican asks the Commission to refocus on whether a seller could exercise market power, not on the physical location where a change in ownership of energy occurs. MidAmerican argues that if a mitigated seller cannot exercise market power over sales made directly in an outside competitive market, such seller cannot exercise market power over sales made in its home control area that are for export to that outside competitive market.[932] Rather than protecting the ultimate buyers, these commenters submit that mitigating such sales would transfer wealth from the mitigated seller to subsequent entities that can charge market prices in later transactions.[933]

802. MidAmerican and the Oregon Commission claim that if the Commission requires mitigated sellers to mitigate all their sales in the mitigated market such an outcome would encourage gaming, such as round-trip or ricochet transactions.[934] MidAmerican maintains that such gaming can be eliminated when mitigation applies only to sales sinking within the mitigated control area.[935]

803. Duke, E.ON U.S., Westar, MidAmerican, Ameren, and Xcel all assert that the availability of supply alternatives to wholesale purchasers should be a determining factor when deciding whether to permit market-based rates for sales that sink in

[924] 114 FERC ¶ 61,280 at P 29–33 (2006), *reh'g pending (MidAmerican).*

[925] *Id.* at P 31.

[926] State AGs and Advocates at 43–44.

[927] APPA/TAPS at 47–48. To limit marketers' arbitrage opportunities, APPA/TAPS suggest limiting any ''must offer'' obligation to sales that sink in the seller's control area. The seller could make additional sales in its control area at the cost-based rate, but would not be obligated to do so because purchasers for loads outside of the seller's control area would presumably have other power supply options.

[928] NYISO at 8–10. The NYISO suggests that the Commission can avoid concerns regarding exports to neighboring markets by applying any cost-based mitigation it imposes to limit the maximum bids that the seller may submit, without limiting the revenues that the mitigated seller may receive. *Id.*

[929] Carolina Agencies at 20.

[930] *See, e.g.*, PPL reply comments at 16.

[931] MidAmerican at 26; Oregon Commission reply comments at 5; *see also* Westar at 20.

[932] MidAmerican at 25–26; *see also* Dr. Pace at 18–20.

[933] MidAmerican at 26; Oregon Commission reply comments at 5.

[934] MidAmerican at 26–27; Oregon Commission reply comments at 6.

[935] MidAmerican at 27.

unmitigated markets.[936] E.ON U.S. points out that the Commission in the April 14 Order noted that the foundation of the market power analysis under the Delivered Price Test is the ''destination market.'' As such, E.ON U.S. asserts that a relevant factor in determining whether to permit a sale at market-based rates should be the level of choice in supply available to the purchaser, not where the product originates.[937]

804. Westar contends that when the buyer is purchasing to serve load in control areas where the seller lacks market power, the buyer presumably has access to other competitive alternatives and has voluntarily entered into the agreement. Therefore, the Commission should not second guess the buyer's decision.[938] Westar adds that prohibiting all sales in the mitigated control area elevates form over substance because parties can simply alter the implementing details of their transaction to accomplish the same result.[939]

805. Westar argues that the Commission's stated concern in *MidAmerican* with a seller's ''ability to attempt to exercise market power over sales in its control area'' is misplaced; the Commission's traditional market power analysis is only concerned with the ''incentive'' and ''ability'' to exercise market power, not with ''attempts'' to do so.[940] As such, it is ''ability'' and not ''attempts'' to exercise market power that is a key determinant of whether an actual market power problem exists.

806. Westar further claims that the Commission is not bound by precedent to prohibit all market-based rate sales in a mitigated control area, pointing out that the Commission has accepted four proposals after the July 8 Order that limit mitigation to sales that sink in the mitigated control areas.[941] Moreover, Westar claims that the July 8 Order appears to address the question of who may buy power from a mitigated seller, not where mitigated sales can occur. This leads Westar to conclude that the Commission did not originally intend to preclude mitigated sellers from making market-based sales to buyers over which the seller lacks generation market power, regardless of where the sales occur. Westar urges the Commission to return to this principle.[942]

807. Xcel urges the Commission to focus on the parties' intent and whether alternative supply options are available to the purchaser at the time of contracting, rather than focusing on where energy purchased in the transaction actually sinks in real time. At the time of the transaction, if the purchaser can confirm: (i) It intends to use the power outside of the mitigated control area, and (ii) there are existing transmission arrangements to actually use the power elsewhere, Xcel maintains that it should not matter what the purchaser subsequently does with the power in real time.[943] Xcel and MidAmerican also favor adopting market-index or proxy based mitigation as a way to reduce the concern about where sales actually sink when trying to ensure proper mitigation.[944]

808. EEI, PPL, PNM/Tucson, and Pinnacle take the position that the Commission should consider point of delivery when deciding whether to permit market-based rate sales.[945] EEI asks the Commission to allow mitigated sellers to make market-based rate sales if the delivery point in the contract or sale confirmation is outside the mitigated market, or if the buyer has transmission service to take the power outside the mitigated market. In other words, buyers who choose delivery points inside the mitigated market and do not move the power out will pay mitigated rates, but buyers who choose delivery points inside the mitigated market but move the power outside the mitigated market will pay market-based rates.[946]

809. EEI asserts that its proposal is consistent with the Commission policy that the mitigation must focus on the geographic market that is mitigated, not the type of customer purchasing the power. EEI concludes that the proposal will minimize the impacts on competitive transactions as well as avoid a remedy that will have a negative impact on the liquidity of the competitive market.[947]

810. PNM/Tucson agree that the Commission should use the point of delivery as a determining factor. They contend that transmission tags alone—which they explain are a reliability tool to ensure systems balance from a transmission perspective—are inadequate to monitor market transactions or ensure that sales sink outside a mitigated control area.[948]

811. PNM/Tucson, Pinnacle, E.ON U.S., MidAmerican and PPL all generally argue that sales at or beyond the transmission interface of a mitigated control area should not be mitigated if the seller lacks market power in the adjacent control area.[949] MidAmerican asserts that the Commission's market power analyses demonstrate that the seller has no market power over sales at the border (sales requiring no additional transmission to exit the mitigated region).[950] PNM/Tucson, Pinnacle and E.ON U.S. maintain that prohibiting market-based rate sales at these transmission interfaces would prevent cross border sales at these unique locations and reduce market liquidity in markets where the seller does not possess market power.[951]

812. E.ON U.S. and MidAmerican urge the Commission to view interface/border transactions as fundamentally different from sales in, or sinking in, a control area. These commenters reason that, at transmission interfaces, a buyer has competitive choices from sellers in both control areas that abut the interface, as well as from any seller that can transmit power to that interface from any control area. As a result, buyers taking title to power at a

[936] Duke at 13; E.ON U.S. at 6; Westar at 20; MidAmerican at 25; Ameren at 19–20; and Xcel at 13.

[937] E.ON U.S. at 6.

[938] Westar at 20.

[939] *Id.* at 21.

[940] *Id.* at 21 (citing *MidAmerican Energy Company*, 114 FERC ¶ 61,280 (2006), *reh'g pending*; *Exelon Corp.*, 112 FERC ¶ 61,011, at P 134 (''As we have said in numerous contexts, we are concerned about a merger's effect on the merged firm's ability and incentive to harm competition.''), *order on reh'g*, 113 FERC ¶ 61,299 (2005); *Oklahoma Gas and Electric Company*, 105 FERC ¶ 61,297, at P 35 (2003) (''Both the ability and incentive to raise prices by restricting access are necessary for a vertical market power problem to exist.''); *NiSource Inc.*, 92 FERC ¶ 61,068, at 61,239 (2000) (''Because the merged company must have both the ability and incentive to adversely affect electricity prices or output, and the merged company will lack the former, no further findings are necessary.'')).

[941] *Id.* at 22 (citing *American Electric Power Service Corp.*, Docket Nos. ER96–2495–026, *et al.* (Jan. 13, 2006) (letter order accepting uncontested settlement applying mitigation to sales that sink in the mitigated control area); *AEP Power Marketing, Inc.*, 112 FERC ¶ 61,320 (2005) (dismissing rehearing requests as moot because of utility's commitment to mitigate sales ''that sink within AEP-SPP''); *South Carolina Electric and Gas Company*, 114 FERC ¶ 61,143 (2006) (order accepting utility's commitment to mitigate sales that ''sink'' in its home control area, subject to a compliance filing); *LG&E Energy Marketing, Inc.*, 113 FERC ¶ 61,229 (2005) (ordering the utility to apply the proposed mitigation to sales that sink in the mitigated control area)).

[942] Westar at 22–23.

[943] Xcel at 13. While MidAmerican does not object to Xcel's proposal, it submits that its own proposal regarding use of market-based indices would provide additional assurance that a seller would not manipulate prices by arranging round-trip transactions into a mitigated control area. MidAmerican reply comments at 19–20.

[944] Xcel at 11–138; MidAmerican reply comments at 4.

[945] EEI at 38; PPL at 25 (supporting EEI's comments); Pinnacle at 9; PNM/Tucson at 14–15.

[946] EEI at 38.

[947] EEI at 41.

[948] PNM/Tucson at 14–15.

[949] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 5–8; MidAmerican at 29–30; PPL reply comments at 16.

[950] MidAmerican at 29–30.

[951] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 8.

transmission interface for delivery outside the mitigated control area have competitive choices that do not require transacting with the supplier found to have market power within the mitigated control area(s).[952] Moreover, E.ON U.S. claims that mitigating transactions at control area interfaces could reduce a utility's profits from off-system sales, thereby affecting retail ratepayers by reducing offsets that affect the costs of their retail rates.[953]

813. PNM/Tucson, Pinnacle, E.ON U.S., and MidAmerican note that the Commission indicated in *LG&E* that sales at the border need not be mitigated along with sales ''wholly in'' a control area.[954] PNM/Tucson and MidAmerican urge the Commission to codify in the Final Rule *LG&E's* holding that sales at the transmission interface of a mitigated control area are not ''in'' the control area, and therefore need not be mitigated.[955] E.ON U.S. similarly asks the Commission to define sales ''in'' a control area as those where title to power transfers at a physical location wholly within such control area, and should not include sales where title transfers at a transmission interface.[956]

814. Xcel, in comparison, argues that any buyer purchasing power at a generator bus or elsewhere in a mitigated control area for purposes of moving that power out of the mitigated market should be treated no differently than a buyer who takes delivery of purchased power outside of the mitigated region. According to Xcel, mitigation to discipline market power is unnecessary in either of these cases and the location of the delivery point does not matter.[957]

815. Both Dalton Utilities and the Carolina Agencies state that it would be wrong to assume that every contract involving a mitigated supplier is unjust and unreasonable and must be abrogated to protect consumers.[958] Dalton Utilities urge the Commission to clearly state in the final rule that it does not generically abrogate existing long-term market-based rate wholesale requirements and transmission contracts, nor is it requiring such abrogation in subsequent proceedings that revoke the market-based rate authority of a public utility found to possess market power.[959] Dalton Utilities asks the Commission to grandfather existing long-term market-based wholesale contracts in the final rule.[960]

816. The Carolina Agencies add that the effect on existing contracts of a decision to retain the current mitigation policy of prohibiting sales at market-based rates in a mitigated market should be determined on a case-by-case basis. These entities reason that simply because market power may exist (or a presumption that it exists has not been rebutted) does not in every instance mean that the seller actually abused its market position to extract unreasonable terms from its purchaser. The circumstances of each contract must be examined to determine whether its terms reflect the exercise of market power. The Carolina Agencies and Dalton Utilities conclude that generic abrogation or reformation of existing agreements is neither warranted nor consistent with the Commission's manner of resolving other claims of broad-based discrimination.[961]

Commission Determination

817. In order to protect customers from market power concerns, we will continue to apply mitigation to all sales in the balancing authority area in which a seller is found, or presumed, to have market power. However, as discussed below we will allow mitigated sellers to make market-based rate sales at the metered boundary[962] between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority under certain circumstances.

818. Commenters advocating allowing market-based rate sales in a mitigated market provided the power is intended for an unmitigated market (*e.g.*, applying mitigation only to sales that sink in the mitigated market) have failed to adequately explain how customers in the mitigated market would be protected from the potential exercise of market power. In addition, commenters have failed to adequately address how the Commission could effectively monitor such sales to ensure that improper sales were not being made. Indeed, several commenters have noted the complex administrative problems that would be associated with trying to monitor compliance with such a policy.[963]

819. Allowing market-based rate sales by a seller that has been found to have market power, or has so conceded, in the very market in which market power is a concern is inconsistent with the Commission's responsibility under the FPA to ensure that rates are just and reasonable and not unduly discriminatory. While we generally agree that it is desirable to allow market-based rate sales into markets where the seller has not been found to have market power, we do not agree that it is reasonable to allow a mitigated seller to make market-based rate sales anywhere within a mitigated market. It is unrealistic to believe that sales made anywhere in a balancing authority area can be traced to ensure that no improper sales are taking place. Such an approach would also place customers and competitors at an unreasonable disadvantage because the mitigated seller has dominance in the very market in which it is making market-based rate sales.

820. However, we do recognize that sales made at the metered boundary for export do lend themselves to being monitored for compliance, and the nature of these types of sales do not unduly disadvantage customers or competitors. Prohibiting market-based rate sales at these metered boundaries of the balancing authority area could prevent or adversely impact cross border sales at these unique locations and reduce market liquidity in markets where the seller does not possess market power. Buyers taking title to power at a metered boundary for delivery to serve load in a balancing authority area where the seller has market-based rate authority have competitive choices and therefore are not required to transact with the seller found to have market power within the mitigated balancing authority area(s).

821. Accordingly, we will allow such sales to be made at market-based rates. Mitigated sellers making such sales must maintain for a period of five years from the date of the sale all data and information related to the sale that demonstrates that the sale was made at the metered boundary between the mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority, that the sale is not intended to serve load in the seller's mitigated market,

[952] E.ON U.S. at 6; MidAmerican reply comments at 22–23.

[953] E.ON U.S. at 8.

[954] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 8; MidAmerican reply comments at 23.

[955] PNM/Tucson at 16; MidAmerican reply comments at 23.

[956] E.ON U.S. at 5.

[957] Xcel at 12.

[958] Dalton Utilities reply comments at 4–9; Carolina Agencies at 22–23.

[959] Dalton Utilities reply comments at 6, 9.

[960] *Id.* at 6–7. Duke notes its support for the Commission's current policy of not reforming or abrogating contracts that were negotiated prior to the time of any finding of market power. Duke reply comments at 8, n.12.

[961] Carolina Agencies at 23; Dalton Utilities reply comments at 7–9.

[962] North American Electric Reliability Corporation. *Glossary of Terms Used in Reliability Standards* at 2 (2007), available at *ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf.*

[963] For example, PNM/Tucson note that transmission tags alone are inadequate to monitor market transactions. PNM/Tucson at 14–15.

and that no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market.

822. Such an approach properly balances commenters' concerns that when a buyer purchases power to serve load in markets where the mitigated seller lacks market power the buyer has access to competitive alternatives with the Commission's obligation under the FPA to ensure that rates are just and reasonable. Further, we find that our approach in this regard does not place an unreasonable burden on the customer, mitigated seller, or competitors. We also emphasize that the mitigation we adopt herein is prospective only. In response to Dalton's concern, we clarify that such mitigation does not modify, abrogate, or otherwise affect existing contractual agreements.[964]

823. Further, we disagree with the Carolina Agencies' contention that short of a ''must-offer'' provision unrestricted exports from a mitigated market increase the prices charged by other suppliers due to scarcity. Carolina Agencies' argument would only apply when the market prices in the first-tier markets are higher than the seller's cost-based rate in the mitigated market. This situation is not necessarily always the case and, therefore, the Carolina Agencies' concern may be based on an unrealistic assumption.

824. We disagree with MidAmerican and the Oregon Commission's claim that if the Commission requires mitigated sellers to mitigate all their sales in the mitigated market this would encourage gaming, such as round-trip or ricochet transactions. While the Commission issued an order rescinding Market Behavior Rules 2 and 6,[965] Order No. 670 finalized regulations prohibiting energy market manipulation pursuant to the Commission's new Energy Policy Act of 2005 authority. The Commission emphasized in Order No. 670 that ''the specific prohibitions of Market Behavior Rule 2 (wash trades, transactions predicated on submitting false information, transactions creating and relieving artificial congestion, and collusion for the purpose of market manipulation), * * * are examples of prohibited manipulation, all of which are manipulative or deceptive devices or contrivances, and are therefore prohibited activities under this Final Rule, subject to punitive and remedial action.'' [966] Such fraud and manipulative conduct therefore remains prohibited and subject to the Commission's anti-manipulation and civil penalty authority.

d. Proposed Tariff Language

Comments

825. Several commenters have proposed specific tariff language in the event the Commission allows market-based rate sales in the mitigated market or at the border. For example, PNM/Tucson would require a sale to ''have a contractual point of delivery at or beyond the transmission interface of the mitigated control area (assuming that the point of delivery is not in another control area where the seller is also mitigated).'' [967] They would also require the seller's market-based rate tariff to explicitly prohibit efforts to collude with a third party to sell to customers in the mitigated control area at market-based rates.[968]

826. PNM/Tucson point out that their proposal contains a significant concession. Under their proposed language, a sale by a mitigated seller at the generation bus in the mitigated control area must be made at mitigated rates. They believe this concession is fair if the Commission insists that market-based rate sales for mitigated sellers are based on contractual points of delivery at or beyond the transmission interface of the mitigated control area. In these companies' view, such an approach would provide needed certainty through a bright line rule and limit factual disputes and investigations.[969]

827. MidAmerican and Ameren also support using tariff or agreement language to ensure power sinks outside of the mitigated market.[970] MidAmerican favors using tariff safeguards and confirmation/oversight procedures to mitigate a seller's ability to exercise generation market power, prevent gaming, and protect wholesale customers in the mitigated region. MidAmerican submits that it has developed and filed market-based rate tariff provisions and verification and oversight procedures that can ensure that export transactions sink outside the mitigated seller's control area.[971] MidAmerican argues that its approach correctly focuses on whether the mitigated seller could exercise market power over transactions that affect entities that purchase on behalf of, or for re-sale to, loads within the market subject to mitigation, rather than the geographical location where customers may take responsibility for transmitting the power to a final destination. Moreover, MidAmerican claims that its proposal would allow the market to work efficiently in areas where the mitigated seller's ability to exercise market power is not an issue. MidAmerican supports a Commission technical conference to further explore this concept with interested parties.[972]

828. Several commenters further propose that mitigated sellers be required to add language to their market-based rate tariffs or to specific market-based rate contracts to restrict re-sales from sinking in the mitigated control area.[973] FP&L argues that requiring such language would reinforce the idea that re-sales into mitigated control areas are violations of a Commission-approved tariff that also, depending on the facts, might violate the Commission's market manipulation regulations.[974]

829. Another commenter agrees that restrictive language in the market-based rate tariff could prevent re-sales into the mitigated control area by helping to ensure that any power purchased at market-based rates within a mitigated control area is exclusively for export to serve loads beyond the mitigated market. Where the Commission is concerned that gaming could lead to the

[964] *See South Carolina Electric and Gas Co.*, 114 FERC ¶ 61,143 at P 18 (2006) (accepting mitigation on a prospective basis; existing long-term agreements remain in effect until terminated pursuant to their terms); *see also* April 14 Order, 107 FERC ¶ 61,018 at P 154; July 8 Order, 108 FERC ¶ 61,026 at P 145.

[965] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 (2006).

[966] *Prohibition of Energy Market Manipulation*, Order No. 670, 114 ¶ FERC 61,047 at P 59 (2006).

[967] PNM/Tucson at 15.

[968] *Id.*

[969] *Id.* at 16–17; MidAmerican submits that its proposal would also provide the ''bright-line'' regulatory certainty sought by PNM/Tucson. MidAmerican reply comments at 16–18.

[970] MidAmerican at 28; Ameren at 19–20.

[971] Under MidAmerican's proposed tariff revisions: (i) Counterparties would be required to affirmatively confirm that the energy sold within MidAmerican's control area will not stay inside that control area; (ii) MidAmerican energy schedulers will review NERC tags associated with in-control area sales on a daily basis to ensure transactions indeed sink outside the mitigated control area; (iii) if a review of the NERC tags shows that a transaction will sink inside the mitigated control area, the sale will be renegotiated at cost-based rates; and (iv) if required by the Commission, MidAmerican would submit the NERC tag data to the appropriate market monitor. MidAmerican at 28–29.

[972] MidAmerican at 28–29.

[973] FP&L at 6 (proposing the following tariff language: ''Purchasers are hereby on notice that the sink for any energy or capacity sale under this Tariff shall not be in the Seller's control area.''); E.ON U.S. at 10 (proposing ''a simple tariff commitment by sellers that power sold at a point of delivery within their mitigated control area will, to the best of their knowledge, sink elsewhere.''); Ameren at 20 (proposing that agreements governing market-based rate sales in mitigated markets explicitly state that the subject power will sink outside the mitigated region, and that the seller be required to report such sales in its EQR).

[974] FP&L at 6.

exercise of market power over wholesale customers in the home control area, this commenter suggests that the Commission reemphasize that efforts to loop power through an adjacent market area in order to raise prices to wholesale customers in mitigated areas above competitive levels is a violation of market-based rate tariffs. Further, this commenter submits that the Commission may require buyers to confirm that power purchased at market-based rates in a mitigated control area is for export, use NERC tag data and transmission scheduling information to verify when purchased power is being exported from the home control area, and require oversight by independent market monitors.[975]

Commission Determination

830. Consistent with our decision above, mitigated sellers choosing to make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority will be required to commit and maintain sufficient documentation to demonstrate[976] that: (1) Legal title of the power sold transfers at the metered boundary between a mitigated balancing authority area and one in which the mitigated entity has market-based rate authorization; and (2) any power sold is not intended to serve load in the seller's mitigated market and (3) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. To accomplish these requirements, mitigated sellers seeking to make market-based rate sales at the metered boundary between their mitigated balancing authority area and a balancing authority area in which the sellers have market-based rate authority must adopt the following tariff provision:

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area where the seller has market-based rate authority; (ii) any power sold hereunder is not intended to serve load in the seller's mitigated market; and (iii) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i), (ii) and (iii) above.

831. This approach affords necessary protection from market power abuse for customers in the mitigated markets. Such language reminds all sellers that gaming resulting in re-sales of any sort by an affiliate of the mitigated seller into their mitigated balancing authority area(s) (*i.e.*, by looping power through adjacent markets) are violations of a Commission-approved tariff that may also, depending on the facts, violate the Commission's market manipulation regulations. Such violations may result in penalties being imposed under the market manipulation regulations and/or the revocation of a mitigated seller's market-based authority in all markets.

E. Implementation Process

Commission Proposal

832. In the NOPR, the Commission put forth several proposals to streamline the administration of the market-based rate program while maintaining a high degree of oversight. The Commission proposed to modify the practice of requiring an updated market power analysis to be submitted within three years of any order granting a seller market-based rate authority and every three years thereafter by, instead, putting in place a structured, systematic review based on a coherent and consistent set of data. First, the Commission proposed to establish two categories of sellers with market-based rate authorization. Sellers in the first category, Category 1,[977] would not be required to file a regularly scheduled updated market power analysis. The Commission proposed instead to monitor any market power concerns for Category 1 sellers through the change in status reporting requirement and through ongoing monitoring by the Commission's Office of Enforcement. In this regard, the Commission noted that failure to timely file a change in status report would constitute a violation of the Commission's regulations and the seller's market-based rate tariff.

833. Sellers in Category 2, consisting of all sellers that do not qualify for Category 1, would be required to file regularly scheduled updated market power analyses in addition to change in status reports. The Commission proposed to codify this requirement in its regulations. Failure to timely file an updated market power analysis would constitute a violation of the Commission's regulations and the seller's market-based rate tariff.

834. Second, to ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposed that the required updated market power analyses be filed for each seller's relevant geographic market(s) on a schedule allowing examination of the individual seller at the same time that the Commission examines other sellers in the relevant markets and contiguous markets within a region from which power could be imported. The Commission appended a proposed schedule for the regional review process, rotating by geographic region with three regions being reviewed per year. For corporate families that own or control generation in multiple control areas and different regions, the Commission proposed that the corporate family would be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.

835. Finally, the Commission proposed to require that all updated market power analyses and all new applications for market-based rate authority include an appendix listing all generation assets owned or controlled by the corporate family by control area, listing the in-service date and nameplate and/or seasonal ratings by unit, and all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family and their location.

1. Category 1 and 2 Sellers

Comments

a. Establishment of Category 1 and 2 Sellers

836. A variety of commenters fully support the Commission's proposed categorization of sellers into two categories and the boundaries of those categories. ELCON comments that the Commission's limited resources should be focused on the dominant players and not treat every seller as a potential threat. NRECA commends the Commission for its attempt to

[975] Dr. Pace at 20–21.

[976] Reliance solely on NERC tag data as documentation for such sales will likely be deemed insufficient as such an approach has not yet been shown to be either workable or effective.

[977] Category 1 sellers would include power marketers and power producers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory. Category 1 sellers also must not own or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or must have been granted waiver of the requirements of Order No. 888 because the facilities are limited and discrete and do not constitute an integrated grid), and they must not present other vertical market power issues. NOPR at P 152.

streamline the process.[978] APPA/TAPS support the proposed categories but suggest that the Commission clarify that it retains the ability to determine that a Category 1 seller must still adhere to the triennial update requirements if, for example, it is dominant in a particular load pocket. Explaining that its generation and power marketing activities are only incidental to its mining operations, and that its market share will likely decline over time, Newmont states that filing an updated market analysis every three years would be an unnecessary burden to prepare and a waste of the Commission's time to review. Newmont finds the 500 MW cutoff a clear, bright line that would be easy to administer. If the Commission determines it necessary to adjust the threshold, however, Newmont suggests retaining the 500 MW cutoff with a further requirement that no more than 250–300 MW be located in any one control area. Alternatively, there could be some sliding scale delineation between Categories 1 and 2 based on the size of a control area, in terms of load, unaffiliated capacity, or both.

837. Financial Companies and Morgan Stanley request that the Commission release a list of all sellers in each category and the region in which the Commission believes each seller belongs to help ensure that sellers have notice of their status and related filing obligations. These parties also suggest that the Commission hold a technical conference on commenters' proposals about how to organize the categories.

838. FirstEnergy opposes the concept of exempting Category 1 sellers from triennial reporting while continuing the requirement for Category 2 sellers. FirstEnergy states that there is no reason for the Commission to require any public utility authorized to sell at market-based rates to file an updated market power analysis. According to FirstEnergy, the showing made in the initial market-based rate proceeding and the change in status rules are adequate, and relieving Category 1 sellers from filing without abolishing the requirement entirely would be unduly discriminatory.

839. On the other hand, the California Commission believes that all sellers should have to continue filing updated market power analyses; it states that the assumption that Category 1 sellers do not need the same level of scrutiny as larger sellers is erroneous, and argues that the NOPR provides no legitimate justification for creating a disparity between Category 1 and 2 sellers. The California Commission continues by stating that reliance solely on market monitoring would not necessarily be effective in California. It notes that in markets utilizing LMP, there is a great potential for sellers to exert ''local'' market power, especially in load pockets. In such load pocket areas, it contends that there is no guarantee that a small seller could not have market power. Further, it states that a Category 1 seller could suddenly gain market power due to another seller's withdrawal from the market and asserts that ''given the number of markets and the Commission's limited resources, it would seem an enormous task of monitoring without requiring regular updated market power analyses from all market participants.'' [979]

840. Similarly, NASUCA states that there is no basis in the record to assume that Category 1 sellers would lack market power at all times and offers examples of when Category 1 sellers could pose a problem.[980] NASUCA also warns that there is no apparent limit on the total amount of exempt generation that could be owned by entities other than those affiliated with a franchised utility. Specifically, NASUCA argues that:

> [U]nder the [Category 1] definition and [change of status] notice obligations, a ''Category 1'' seller could qualify for exemption from triennial market power reviews even if its holding company affiliates—other power marketing and generation entities that also have ''Category 1'' status—collectively have a share of generation far larger than 500 MW, and even if the seller has a retail affiliate without a franchised service territory. Examples might include a group of ''Category 1'' peaker plant owners in a constrained area, each owned by a separate entity affiliated with the same holding company; owners of a fleet of small hydro facilities, each a separate entity within a holding company structure; or an assemblage of generation control [sic] by numerous power marketing subsidiaries, each of which controls less than 500 MW of generation.[981]

841. Thus, NASUCA argues that the regulations should be modified or clarified to prevent this scenario. If the Commission proceeds with its proposal, NASUCA states that the Commission should consider a much lower threshold, such as 75 MW.

842. State AGs and Advocates state that exempting entities, no matter how small, would conflict with the concept that all sellers contribute in varying degrees to the existence of market power in a market.[982]

843. NASUCA and the California Commission argue that none of the proponents of an exempt category of sellers have shown how the exemption meets the Commission's legal requirements.[983] NASUCA expresses concern that the blanket exemption for Category 1 sellers from filing updated market power reviews is inconsistent with the justification the Commission has previously made to the courts in support of market-based rates, namely, that the Commission makes a discrete finding or determination as to each seller's market power, and periodically reviews it. The California Commission similarly disputes that the exemption meets the underlying principle found in *Lockyer.* It states that the Ninth Circuit in that case noted that the Commission's authority to grant market-based rates is rooted in the integral nature of the reporting requirements. The California Commission asserts that the proposed requirement for Category 1 sellers to make a filing only upon a change in status is inconsistent with the rationale laid out in *Lockyer.* It further contends that delegation of ongoing monitoring to the Commission's Office of Enforcement is vague and contrary to the underlying principle found in *Lockyer.* According to the California Commission, the assumptions underlying the proposed Category 1 exemption (that since Category 1 sellers are smaller in size they do not need to be subject to the same requirements and scrutiny as larger sellers of energy, and that '' 'Category 2 sellers are the larger sellers with more of a presence in the market and are more likely to fail one or more of the indicative screens or pass by a smaller margin than Category 1 sellers'' ') are insufficient to justify a departure from the *Lockyer* rationale.[984]

844. PPM refutes the California Commission's arguments. First, PPM asserts that the California Commission is wrong in its generalization that a seller that controls less than 500 MW in a market that utilizes LMP could exert

[978] *See also* EPSA reply comments at 3, 13–14.

[979] California Commission at 4.

[980] For example, NASUCA asserts that there appears to be a possibility that a seller with a fleet of newer power plants that were initially exempted from review would be totally exempt from subsequent review based on the size of the power plants. These sellers might at times have market power with respect to ancillary services. NASUCA further submits that changed circumstances, such as declining reserve margins, might create opportunities for seemingly small sellers to exercise market power.

[981] NASUCA at 12. *See also* NASUCA reply comments at 9–11 (stating that neither the 500 MW exemption, nor the expansion to a 1000 MW exemption, nor the elimination of a horizontal market power test, should be adopted).

[982] State AGs and Advocates reply comments at 14.

[983] NASUCA reply comments at 9–11, California Commission reply comments at 1–4.

[984] California Commission reply comments at 3–4 (quoting NOPR at P 153).

local market power. PPM argues that the existence of an LMP market does not increase the potential for a small generator or marketer to possess market power; LMP is intended to reduce the ability of a party to exercise local market power.[985] Second, PPM states that the California Commission is wrong when it asserts that *Lockyer* requires the Commission to require all sellers to file updated market power analyses. According to PPM, in *Lockyer,* the Court found that if the Commission is going to grant parties the authority to charge market-based rates, the Commission must continue to monitor and ensure that the rates charged are just and reasonable. PPM submits that creating a categorical exemption to reduce the burden on smaller generators and marketers does not mean that the Commission is eliminating its ability to effectively monitor the wholesale electric market. It states that the Commission retains the tools necessary to ensure that all rates are just and reasonable: all entities with market-based rate authority must submit electric quarterly reports to the Commission regarding their transactions; all parties have the right to ask the Commission for relief under section 206 of the FPA if they believe that rates are improper or unjust; the Commission may take up an independent review of any markets which are displaying abnormal characteristics; and finally, the Commission may require certain parties to file updated market power analyses if the seller is found to have market power even if the seller meets the threshold for Category 1 exemption.

b. Threshold for Category 1 Sellers and Other Proposed Modifications

845. While the majority of commenters support the concept of exempting smaller, Category 1 sellers from filing updated market power analyses, many seek clarification or modification of the proposal. A number of commenters propose a threshold other than ownership or control of 500 MW or less in aggregate. Suggested thresholds include: 500 MW or less of uncommitted capacity (therefore including only that which is available for sale into markets during peak periods);[986] 500 MW within a particular control area;[987] 500 MW within a geographic market;[988] 500 MW within a particular region;[989] up to 1000 MW;[990] less than 1 percent of the installed capacity in a regional market or 1000 MW in that regional market (whichever is higher);[991] or some other formula.[992] Several commenters urge the Commission to consider the size of a particular control area or geographic region or market and whether the geographic market is served by an RTO/ISO,[993] and to take into account the difference between thermal generating capacity and intermittent or non-dispatchable generation for their ability to impact the competitiveness of a market.[994]

846. PPM argues that without certain modifications to the Commission's definition of a Category 1 seller, which PPM believes is too narrowly defined, many generators and marketers may needlessly have to submit an updated market power analysis. According to PPM, the Commission should not eliminate the exemption for new generation (pursuant to 18 CFR 35.27(a)) without expanding the group of generators and marketers eligible for Category 1 status.[995] Several commenters also urge the Commission to allow fact-specific requests for exemption from filing requirements for those sellers who otherwise would qualify as Category 2 sellers[996] or other particular exemptions.[997]

847. In addition, Constellation proposes specific modifications to the proposal. First, Constellation requests that the Commission change the affiliation standard in the definition of Category 1 sellers to be consistent with other definitions set forth in the NOPR. Because the proposed language would exclude from the definition of Category 1 sellers any affiliate of a public utility with a franchised service territory regardless of whether it has captive customers, Constellation suggests using the defined term ''franchised public utility''[998] instead of ''public utility with a franchised service territory.'' Constellation states that the exclusion should only apply to affiliates of public utilities with captive customers. Second, Constellation argues that a company should be considered to be a Category 1 seller so long as it is not affiliated with a ''franchised public utility'' in the same geographic region. It explains that, with this change, a company would qualify as a Category 1 seller in California despite the fact that it is affiliated with a franchised public utility in New England because any concerns about affiliate abuse would exist only in the New England market and not in California.[999] Third, Constellation suggests that, if operational control over transmission facilities has been transferred to an RTO/ISO, then a seller's affiliation with the owner of such transmission facilities should not exclude the seller from qualifying as a Category 1 seller. Further, Constellation seeks clarification that the exclusions for owners of transmission facilities that are simply interconnection facilities, are under operational control of an RTO/ISO, or are subject to waiver of Order No. 888 and 889, will also apply to affiliates of those transmission owners.

Commission Determination

Adoption of Category 1/Category 2

848. We adopt the NOPR proposal to create a category of sellers that are exempt from the requirement to automatically submit updated market power analyses, with certain modifications. As discussed further

[985] PPM reply comments at 1–3.

[986] *See* Ormet at 9.

[987] *See, e.g.,* PPM at 3–4; AWEA at 3–4.

[988] *See* Constellation at 8–9 (noting that this would be consistent with the Commission's indicative screen analysis and regional approach to updated market power analyses).

[989] EPSA at 36–37; AWEA at 3–4; Suez/Chevron at 5–10.

[990] *See* Morgan Stanley at 10–13; Financial Companies at 13–14; Financial Companies reply comments at 7–8. *See also* Mirant at 12 (recommending 1000 MW per geographic market if the Commission hopes to have a minimal impact on sellers' compliance costs caused by eliminating the 18 CFR 35.27(a) exemption).

[991] EPSA at 36–37.

[992] Constellation at 9–11 (supports changing threshold from 500 MW to the greater of 500 MW or 2 percent of the total generation capacity in the relevant geographic market; where the geographic market is an RTO or ISO, change threshold to the greater of 1,000 MW or 2 percent of the total generation capacity in that market); Ameren at 21 (supports exempting a company that owns or controls more than 500 MW but owns or controls less than 20 percent of the total uncommitted capacity in the relevant geographic market and also is not affiliated with an entity that owns transmission facilities in that market).

[993] Drs. Broehm and Fox-Penner at 13; Constellation at 9; PPM at 3–4.

[994] AWEA at 3–4 (asserting that companies owning or controlling thermal generating capacity have a greater opportunity for impacting the competitiveness of a market than those that own or control non-dispatchable generation, such as wind power facilities, that rarely achieve production at nameplate capacity levels); PPM at 4 (same); Financial Companies reply comments at 8–9.

[995] PPM at 3–5.

[996] *See* Morgan Stanley; Financial Companies.

[997] *See, e.g.,* Ormet at 7–11 (exemption for self use/supply, *i.e.,* capacity used to self supply a corporate affiliate and presumptively unavailable for sale into markets); TXU at 4–5 (case-by-case determination of whether a seller's affiliation with an entity that owns or controls Commission-jurisdictional transmission presents the possibility of vertical market power concerns).

[998] Proposed 18 CFR 35.36(a)(5) defines a franchised public utility as ''a public utility with a franchised service obligation under state law and that has captive customers.''

[999] Similarly, Constellation contends that, if a seller and its affiliates own more than 500 MW of generation capacity in only one region and less in others, then the seller should be required to file updated market power analyses in only the region(s) where its affiliated generation exceeds the threshold.

below, this finding is fully consistent with our statutory obligation to ensure just and reasonable rates and with court decisions construing that obligation. Moreover, it will streamline the administration of the market-based rate program by focusing the Commission's resources on sellers that have a significant presence in the market. It also is supported by the majority of commenters in this proceeding.

849. The Commission agrees with Financial Companies and Morgan Stanley that sellers should have notice of their status and related filing obligations. However, we believe the criteria we adopt herein are sufficiently clear so that the vast majority of sellers can easily determine in which category they fall. Accordingly, the Commission will not initially compile and release a list of sellers in each category. Rather, we will require all sellers that believe they fall into Category 1 to make a filing with the Commission at the time that updated market power analyses for the seller's relevant market would otherwise be due (based on the regional schedule for updated market power analyses adopted in this Final Rule). That filing should explain why the seller meets the Category 1 criteria[1000] and should include a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area.[1001] The Commission will notice these filings and provide an opportunity for comment. The Commission will then act on the seller's filing, either acknowledging that the seller falls within Category 1 or, if it finds that the seller does not qualify as a Category 1 seller, directing the seller to file an updated market power analysis. Subsequently, all Category 1 sellers will not be required to file regularly scheduled updated market power analyses.

850. With regard to sellers that fall into Category 2, these sellers will be required to file an updated market power analysis based on the schedule in Appendix D. In our orders acting on the updated market power analyses, the Commission will make a finding that the seller is a Category 2 seller, as appropriate.

851. In addition, with regard to new applications for market-based rate authority, we also will make a finding regarding the category in which the seller falls. However, all sellers submitting initial applications for market-based rate authority must submit the indicative screens, or accept a presumption of market power in generation, and must submit a vertical market power analysis.

852. We reject FirstEnergy's argument that there should be no requirement for any seller to file an updated market power analysis. Competitiveness of markets is continuing to change and, therefore, we are reluctant to rely only on initial market power analyses, change in status filings, and section 206 complaints in all cases. The burden on Category 2 sellers is small compared to their market presence and activities, and is outweighed by the fact that submission of periodic updated market power analyses enhances Commission oversight and public confidence in the regulatory process. Thus, we will require the submittal of regularly scheduled updated market power analyses by those sellers that have more of a presence in the market and are more likely to either fail one or more of the indicative screens or pass by a smaller margin than those that will qualify as Category 1 sellers, or that may present circumstances that could pose vertical market power issues, *i.e.*, Category 2 sellers. Through regularly scheduled updated market power analyses for Category 2 sellers, the Commission is better able to evaluate the ongoing reasonableness of those sellers' charges and to provide for an ongoing assessment of their ability to exercise market power. In the absence of regularly scheduled updated market power analyses from the Category 2 sellers, it would be more difficult for the Commission to fulfill its statutory duty to ensure that market-based rates are just and reasonable and that market-based rate sellers continue to lack the potential to exercise market power so that market forces are indeed determining the price.

853. Because Category 1 and 2 sellers occupy different postures in terms of their presence in the market, it is not unduly discriminatory to eliminate the requirement to file a regularly scheduled updated market power analysis for Category 1 sellers but not Category 2 sellers. Category 1 sellers have been carefully defined by the Commission to have attributes that are not likely to present market power concerns: ownership or control of relatively small amounts of generation capacity; no affiliation with an entity with a franchised service territory in the same region as the seller's generation facility; little or no ownership or control of transmission facilities and no affiliation with an entity that owns or controls transmission in the same region as the seller's generation facility; and no indication of an ability to exercise vertical market power. Further, based on a review of past Commission orders, we are aware of no entity that would have qualified as a Category 1 seller under this Final Rule but would nevertheless have failed our indicative screens necessitating a more thorough analysis. Thus, the Commission has provided a reasoned basis to distinguish Category 1 sellers from Category 2 sellers. Moreover, the EQR reporting requirements and change in status filings required for Category 2 market-based rate sellers will also apply to Category 1 sellers. This will ensure adequate oversight of Category 1 sellers, even without regularly scheduled updated market power analyses. Further, we will continue to reserve the right to require an updated market power analysis from any market-based rate seller at any time, including for those sellers that fall within Category 1.

854. In this regard, we agree with PPM that the Commission retains the tools necessary to ensure that all rates are just and reasonable, including initial market power evaluations, and ongoing monitoring by the Commission. For example, as noted above, all sellers with market-based rates must file electronically with the Commission an EQR of transactions no later than 30 days after the end of the reporting quarter and must comply with the change in status reporting requirement. We note that the reporting requirement relied upon by the court in *Lockyer* is the transaction-specific data found in EQRs, which we continue to require of all sellers, and not updated market power analyses. Thus, exempting Category 1 sellers from routinely filing updated market power analyses does not run counter to *Lockyer.*

855. With respect to EQR filings, the Commission enhanced and updated the post-transaction filing requirements from what they were during the period at issue in the Lockyer case, now requiring electronic reporting of, among

[1000] These criteria, as modified in this Final Rule, include wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.

[1001] In the section titled ''Regional Review and Schedule'' we discuss further how we implement this approach.

other things:[1002] (1) A summary of the contractual terms and conditions in every effective service agreement for market-based power sales; and (2) transaction information for effective short-term (less than one year) and long-term (one year or greater) market-based power sales during the most recent calendar quarter. We also note that the Commission has revoked the market-based rate authority of sellers that have failed to comply with the EQR filing requirements.[1003] Further, the Commission has utilized EQR data in determinations relating to market power. For example, the Commission relied in part on EQR data in reaching its determination that an ''alternative'' market power analysis submitted by Duke Power was unpersuasive.[1004]

856. With respect to notices of change in status, in a related rulemaking proceeding in early 2005, the Commission clarified and standardized market-based rate sellers' reporting requirement for any change in status that departs from the characteristics the Commission relied on in initially authorizing sales at market-based rates.[1005] In Order No. 652, the Commission required that, as a condition of obtaining and retaining market-based rate authority, sellers must file notices of such changes no later than 30 days after the change in status occurs.[1006] These requirements are codified in our regulations, and failure of a market-based rate seller to timely file a change in status report constitutes a tariff violation. If such a violation occurs, the Commission has the tools available to impose remedies, as necessary and appropriate, from the date on which the tariff violation occurred. Such remedies could include disgorgement of profits, civil penalties or other remedies the Commission finds appropriate based on the specific facts and circumstances.

857. We note that any new market-based rate seller must conduct a horizontal market power analysis for our review. Furthermore, we reiterate that the Commission retains the ability to require an updated market power analysis from any seller, Category 1 or 2, at any time.

858. We also reject those arguments made by the California Commission, NASUCA, and State AGs and Advocates that all sellers should continue to be required to file regularly scheduled updated market power analyses. For the reasons stated above, assertions that the Commission will be unable to monitor market-based rate sellers without requiring all sellers to file regularly scheduled updated market power analyses are unfounded.

859. In response to the comments of NASUCA and Constellation, we make the following clarifications. We clarify that, subject to other conditions discussed below, Category 1 sellers include power marketers and power producers with 500 MW or less of generation capacity owned or controlled by the seller and its affiliates in aggregate per region. Our use of the term ''region'' is intended to be as delineated in the Regional Review and Schedule attached as Appendix D.

860. We further clarify that a seller that owns, operates or controls, or is affiliated with an entity that owns, operates or controls, transmission facilities in the same region as the seller's generation assets does not qualify as a Category 1 seller in that region. This standard applies regardless of whether the total generation capacity owned or controlled by the seller and its affiliates is below 500 MW in the region.

861. Regarding Constellation's point that a company should be considered Category 1 so long as it is not affiliated with a franchised public utility in the same region (and meets the other requirements for Category 1), we concur. Hence, a seller that is affiliated with a franchised public utility that is not in the same region in which the seller owns or controls generation assets may qualify as a Category 1 seller for that region if it meets the other Category 1 criteria. Likewise, a seller that does not own, operate or control, and is not affiliated with an entity that owns, operates or controls, transmission in the same region in which the seller owns or controls generation assets may qualify as a Category 1 seller for that region.

862. We do not adopt Constellation's proposal that we carve out an exemption for sellers affiliated with a franchised public utility without captive customers nor do we adopt the proposal to exempt those that are affiliated with transmission owners that have given operational control of their transmission facilities to RTOs/ISOs.[1007] Constellation has failed to adequately demonstrate that sellers affiliated with a franchised public utility without captive customers and those that are affiliated with transmission owners that have given operational control of their transmission facilities to RTOs/ISOs necessarily lack market power in generation.

863. In addition, we will revise the definition of Category 1 sellers in the regulations to include those that own, operate or control only transmission facilities that are ''limited equipment necessary to connect individual generating facilities to the transmission grid.'' While the NOPR included this language in the preamble, conforming language was inadvertently excluded from the definition of Category 1 sellers in § 35.36(a)(2) of the proposed regulations.

Threshold for Category 1

864. After considering all of the comments regarding the proposed cutoff between Categories 1 and 2, we believe that 500 MW or less of generating capacity per region is an appropriate threshold. We will use this value as a cutoff because, during our 15 years of experience administering the market-based rate program, there have only rarely been allegations that sellers with capacity of 500 MW or less had market power, and when those claims have been raised the Commission's review has either found no evidence of market power or found that the market power identified was adequately mitigated by Commission-enforced market power mitigation rules.[1008] While some commenters urge the Commission to adopt either a higher or lower threshold, the Commission believes that a 500 MW threshold is both a reasonable balance as well as conservative enough to ensure that those unlikely to possess market power will be granted market-based rate authority. Moreover, as Newmont asserts, 500 MW is a clear, bright line that will be easy to administer.

[1002] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002). Required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001. The EQR must be submitted to the Commission using the EQR Submission System Software, which may be downloaded from the Commission's Web site at *http://www.ferc.gov/docs-filing/eqr.asp.* The exact dates for these reports are prescribed in 18 CFR 35.10b. Failure to file an EQR (without an appropriate request for extension), or failure to report an agreement in an EQR, may result in forfeiture of market-based rate authority, requiring filing of a new application for market-based rate authority if the seller wishes to resume making sales at market-based rates.

[1003] *See Electric Quarterly Reports,* 115 FERC ¶ 61,073 (2006); *Electric Quarterly Reports,* 114 FERC ¶ 61,171 (2006); *Electric Quarterly Reports,* 69 FR 57679 (Sept. 27, 2004); Electric Quarterly Reports, 105 FERC ¶ 61,219 (2003).

[1004] *Duke Power, a Division of Duke Energy Corporation,* 111 FERC ¶ 61,506 at P 48, 55 (2005).

[1005] Order No. 652 at P 47.

[1006] As discussed below in the Change in Status section, the Commission is modifying its regulations to provide that, in the case of power sales contracts with future delivery, such contracts are reportable 30 days after the physical delivery has begun.

[1007] We do, however, replace the term ''public utility with a franchised service territory'' with the defined term ''franchised public utility.''

[1008] Moreover, as noted above, the Commission's indicative screens are set at conservative levels.

865. In addition and in response to commenter requests, we clarify that the 500 MW threshold is determined by adding all the generation capacity owned or controlled by the seller and its affiliates within the same region (as delineated in the Regional Review and Schedule attached as Appendix D). In keeping with our conservative approach with regard to which entities qualify for Category 1, we find that aggregate capacity in a given region best meets our goal of ensuring that we do not create regulatory barriers to small sellers seeking to compete in the market while maintaining an ample degree of monitoring and oversight that such sellers do not obtain market power. In this regard, we also clarify that although we will use aggregate capacity owned or controlled in a region to determine which sellers are required to file regularly scheduled updated market power analyses, we will continue to evaluate the balancing authority area in which the seller is located when performing our indicative screens, absent evidence to the contrary.[1009]

866. While we recognize the appeal of a test that takes into account the size of each geographic market, such as using a percentage of all capacity (as opposed to a stated MW) cutoff and the use of uncommitted capacity rather than installed capacity, these methodologies are inconsistent with a straightforward, conservative means of screening sellers and consequently would lead to regulatory uncertainty. As markets and market participants can fluctuate, a determination of the number of MWs constituting a particular percentage of capacity in a regional market would have to be constantly recalculated and the assumptions underlying a determination could lead to potential challenges. Such an approach would run counter to our intention to provide certainty to market participants and to streamline the administration of the program.

867. The Commission rejects as unnecessary suggestions by AWEA and PPM that we take into account the differences among generation, including that classified as intermittent or non-dispatchable, when calculating the generation capacity of a seller. We believe that many sellers with wind and other non-thermal capacity will fall below the 500 MW threshold; those that do not may take advantage of simplifying assumptions and other means to minimize the burden of filing an updated market power analysis.

868. With respect to several commenters' desire for fact-specific exemptions for sellers who otherwise may qualify for Category 2, we note that the Commission will determine on a case-by-case basis the category status of each seller with market-based rate authorization. In our attempt to keep the Category 1 criteria as simple and straightforward as possible, we may have swept under Category 2 particular sellers whose circumstances make it unlikely that they could ever exercise market power. As a result, we will entertain and evaluate individual requests for exemption from Category 2 and make a finding on the category status of each company. However, if a seller wishes to request exemption from Category 2, it must make a filing seeking such an exemption no later than 120 days before its next updated market power analysis is due. We also will consider any arguments from intervenors that a particular seller that contends that it qualifies for Category 1 status based on our definition should nevertheless be treated as a Category 2 seller and thus be required to continue filing updated market power analyses.

2. Regional Review and Schedule

Commission Proposal

869. To ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposed to require ongoing updated market power analyses to be filed for each seller's relevant geographic market on a pre-determined schedule. Such a process would allow examination of the individual seller at the same time that the Commission examines other sellers in the relevant market and contiguous markets within a region from which power could be imported. The Commission appended to the NOPR a proposed schedule for the regional review process, rotating by geographic region with three regions being reviewed per year. For corporate families that own or control generation in multiple control areas and different regions, the Commission proposed that the corporate family would be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.

Comments

870. Several commenters, including ELCON, APPA/TAPS, NRECA, Suez/Chevron, and Newmont, support the Commission's proposal. ELCON states that the requirement that a seller file its updated market power analysis at the same time the Commission examines other sellers in the relevant market and region is an excellent idea because it provides a better picture to the Commission during its review. APPA/TAPS state that the regional approach will lead to data consistency and availability, and will allow the Commission to fulfill its obligations more completely. Newmont believes that the Commission's proposal appropriately balances the need to effectively monitor and mitigate market power while avoiding unnecessary and unproductive regulatory requirements.[1010]

871. Alternatively some commenters oppose the proposal entirely, or suggest modifications. Reliant states that the regional review and schedule would significantly increase the administrative burdens of compliance rather than streamline them. According to Reliant, companies that engage in business in multiple regions of the United States would have to file several times over the three year schedule instead of once as is required currently.[1011] Morgan Stanley and Financial Companies state that the Commission should require Category 2 sellers to file only once every three years, either with the region where they have a franchised service territory or the region in which they own the greatest amount of generation. EEI and EPSA maintain that a regional review will pose a great burden on utilities operating in multiple markets and will lead to confusion over contradictory information.[1012]

872. State AGs and Advocates warn that the regional approach will result in a too infrequent analysis of each area. They and others state that, with the combined approach, each specific region will only be looked at completely every three years, which is less oversight than the Commission has currently.[1013]

873. FirstEnergy notes that the Commission has encouraged PJM and Midwest ISO to eliminate ''seams'' between their respective regions and comments that the proposal to schedule submittal of updated market power analyses for sellers in these two regions

[1009] As we have stated above, where a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (*i.e.*, the balancing authority area in which the generator is located).

[1010] Newmont at 1.

[1011] Similarly, Allegheny, Mirant, FP&L, EEI, FirstEnergy, MidAmerican, TXU, Morgan Stanley, Financial Companies, and EPSA argue that large corporate families could find themselves in a perpetual triennial review that would place a substantial regulatory burden and expense on them.

[1012] EEI reply comments at 27–29, EPSA reply comments at 11–14.

[1013] *See, e.g.*, State AGs and Advocates at 49–51, Reliant at 9–11, Mirant at 2–6, EPSA at 39–40, EEI reply comments at 27–29, EPSA reply comments at 11–14.

at different times is inconsistent with the reasons underlying adoption of common filing dates. Mirant states that the limited number of consultants that perform market power analyses use separate, proprietary databases and warns that the market data submitted on a regional basis will remain inconsistent. Further, Mirant asserts that there may be antitrust issues if a group of competing sellers jointly hires one consultant.

874. NRECA replies that any increase in the burden on sellers does not outweigh the substantial benefits of greater data consistency and a complete picture of each region under review.[1014] APPA/TAPS assert that the Commission should not sacrifice improvements to its program for the interests of a few companies and that any increased cost to companies associated with regional reviews is outweighed by the companies' profits from market-based rate sales. They dismiss concerns regarding a scarcity of consultants, noting that the market should respond to an increase in demand for consulting services, and that ''competition will force efficiency gains to be passed along to consultants'' clients.'' [1015] Further, with respect to a group of sellers jointly hiring a consultant to produce a market analysis, they comment that antitrust counsel should be able to ensure joint representation does not result in improper information sharing.[1016]

875. PNM/Tucson state that the updated market power analyses in a given region should be deliberately staggered so that utilities are able to build upon data sets already submitted in prior proceedings, instead of each having to construct its own, which would result in varying, competing data sets.

876. Mirant and FP&L add that with all the entities filing concurrently it will be difficult for some, such as non-transmission owning entities, to acquire the necessary data (*i.e.*, simultaneous import limit data). NRECA, Mirant and Powerex ask the Commission to have transmission-owning utilities file their updated market power analyses (or information necessary for others to perform preliminary screens) at a minimum 90 days prior to the regional due date; MidAmerican requests that the Commission require each transmission provider to post to its OASIS a simultaneous import study 60 days before the filing deadline that could be used by first-tier entities to develop their market power analyses. Similarly, Suez/Chevron suggests requiring RTOs and/or control area operators in each region to file certain information in advance of the filing deadline so that sellers can rely on uniform baseline data.[1017] EEI critiques the proposals for sharing of data prior to submission of triennial reviews, stating that this would increase the complexity of an already cumbersome process.[1018]

877. APPA/TAPS state that data sharing by companies should be enhanced by regional reviews, not impaired, and that more robust data and opportunities to reconcile conflicting submissions with a regional review will lead to a better analysis by the Commission.[1019]

878. MidAmerican asserts that the Commission should allow more time between the end of the qualification period and the filing of market power analyses. It states that these analyses require Form 1 data that is not available until several months after the end of the calendar year and that control area loads as filed in Form 714 are frequently not available until the third quarter following the end of the calendar year, usually July. Additionally, it states that generation and load data from Forms EIA–860 and EIA–861, respectively, are likewise not available until late in the following year. Accordingly, it suggests that market analyses should not be due until mid-October following the end of the qualification period, allowing roughly 90 days between the availability of Form 714 and the deadline for filing.[1020]

879. Many commenters also argue that the Commission should extend the time until the first regional reviews are due. Suggested beginning filing dates include: the first filing period for a region that is no earlier than a company's next required updated analysis; [1021] the first filing period that occurs no earlier than two years from the latest filed updated analysis; [1022] the first filing period that is no earlier than one year from the latest filed updated analysis; [1023] or 180 days after the Final Rule is published in the **Federal Register**.[1024] Duke suggests that, rather than extending the first filing times, the Commission clarify that those entities due to file their next updates before the scheduled regional reviews are due can forgo making any interim filings.

880. APPA/TAPS ask the Commission to extend the period for commenting on the updated market power analyses from the current 21-day comment period to 60 days, at a minimum. They state that because numerous sellers will file the updated market power analyses contemporaneously, intervenors should be given sufficient time to make meaningful use of the expanded body of information and to prepare multiple pleadings dealing with various sellers in the region. They add that the additional time should improve the quality of the analyses that the Commission receives from intervenors.

881. Finally, regarding the Commission's proposal to require all updates (and all new applications) to include an appendix listing all generation assets owned or controlled by the corporate family, in-service dates and capacity ratings by unit, Duke agrees with the proposal that the appendix should also reflect all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family. It states that having such a standardized listing will be helpful both to the Commission and to other market participants.[1025] Duke cautions, however, that including the location of transmission and gas pipeline facilities in the appendix could conflict with CEII requirements, and requests clarification that sellers will have discretion with locational descriptions.

Commission Determination

882. The Commission adopts the NOPR proposal to conduct a regional review of updated market power analyses, with certain modifications. We agree with commenters such as APPA/TAPS that the regional approach will lead to data consistency and availability. In this regard, both the Commission and market participants will benefit from greater data consistency that will result from regional examination of updated market power analyses and a methodical study of all sellers in the same region. This will give the Commission a more complete view of market forces in each region and the opportunity to reconcile conflicting submissions, enhancing our ability to ensure that sellers' rates remain just and reasonable.

883. Although some commenters express concern that a regional review approach will increase administrative

[1014] NRECA reply comments at 28–30.

[1015] APPA/TAPS reply comments at 20.

[1016] *Id.* at 19–21.

[1017] The data Suez/Chevron refer to include the information indicated in proposed Appendix C, Pivotal Supplier Analysis at Rows E through J, O, P and Q and also proposed Appendix C, Wholesale Market Share Analysis at Rows F through Q, and the accompanying workpapers.

[1018] EEI reply comments at 27–29.

[1019] APPA/TAPS reply comments at 19–21.

[1020] *See* MidAmerican at 33.

[1021] *See* Consumers at 2–4, Allegheny at 16–18.

[1022] *See* MidAmerican at 30–33.

[1023] *See* Constellation at 13.

[1024] *See* Allegheny at 16–18.

[1025] Duke at 49.

burdens, particularly for sellers operating in multiple regions, we believe that the Commission's proposal properly and fairly balances the need to effectively monitor and mitigate market power in wholesale markets with the desire to minimize any administrative burden associated with the filing and review of updated market power analyses. While we recognize that some sellers may have to file updates more frequently than they do currently, we have carefully balanced the interests of all involved, and we believe that regional reviews of updated market analyses is both needed and desirable and will enhance the Commission's ability to continue to ensure that sellers either lack market power or have adequately mitigated such market power.

884. We note that sellers currently must prepare a market power analysis for all of their generation assets nationwide. Some sellers with assets in multiple regions have chosen to submit their individual updated market power analyses when each is due (every three years) rather than combining them into a single updated market power analysis. Others file one updated market power analysis for the entire corporate family, with individual analyses of the different markets in which their assets are located. Either way, the same analyses must be filed under the status quo and the approach adopted in this Final Rule. The timing may differ, but the increased burden is minimal.[1026]

885. Nevertheless, considering the comments received and upon further review of the Commission's proposal, we believe that some of the proposed regions should be consolidated. Therefore, we will reduce the number of regions from the proposed nine to six. In Appendix D we identify the six regions (Northeast, Southeast, Central, Southwest Power Pool, Southwest, and Northwest), and will require Category 2 sellers that own or control generation assets in each region to file an updated market power analysis for that region every three years based on a rotating schedule shown in the Appendix.[1027] We believe that, with fewer and larger regions, some sellers will likely be present in fewer regions and administrative burdens for those sellers accordingly will be reduced. In addition, the decrease in the number of regions will also extend the time period between filings. In the NOPR, the Commission stated that three regions would be reviewed per year, with four months between each set of filings. Here we adopt review of two regions per year, with the filing periods six months apart.

886. Regarding FirstEnergy's argument that PJM and Midwest ISO should be placed in the same region, we continue to encourage PJM and the Midwest ISO to address ''seams'' issues. However, we find that placing them in different regions for the purpose of determining when an updated market power analysis is submitted should in no way affect or discourage efforts to address seams between these two regions. Other considerations (such as balancing RTO/ISO and non-RTO/ISO filings, and scheduling approximately the same number of filings each year) outweigh FirstEnergy's concerns.

887. The Commission rejects the arguments by some commenters that the regional approach will result in too infrequent an analysis of each area. As a practical matter, currently sellers are required to file an updated market power analysis every three years. In the intervening years between updated market power analyses, most utilities either enjoy the 18 CFR 35.27(a) exemption from filing a generation market power analysis or rely on the previously filed updated market power analysis. The regional approach will provide the Commission with a snapshot of sellers across a larger area and will provide a more accurate view of simultaneous import capability into the relevant geographic markets under review. Accordingly, contrary to claims that the regional approach will result in less Commission oversight, the regional approach will enhance the Commission's ability to analyze market power using better data with less opportunity for conflicting claims of ownership or control of generation assets.

888. Regarding concerns about the scarcity of consulting firms, we note that our proposal will not necessarily increase the number of market power analyses to be performed (indeed, by exempting all Category 1 sellers from submitting updated market power analyses, the number may be decreased). We agree with APPA/TAPS that any shortage of consultants performing market power analyses should be temporary as firms adjust to a new schedule reflecting the regional review timetable and take precautions to prevent improper information sharing.

889. We agree with commenters that transmission-owning entities should file their updated market power analyses in advance of others in each region. Thus, the Commission will modify the schedule proposed in the NOPR to better allow sellers to rely on the transmission-owning utilities' information, and we will adopt a staggered filing approach for each region which will require different types of entities to file at different times. The transmission-owning utilities, which have the information necessary to perform SIL studies, will be required to file their updated market power analyses first. Six months later, all others in that region will be required to file their updated market power analyses.[1028]

890. Staggering the time periods within which transmission-owning and non-transmission-owning utilities will be required to submit their updated market power analyses will provide an opportunity for those non-transmission owning sellers that need simultaneous transmission import limits to perform the screens to rely on the SIL studies performed by the transmission-owning utilities rather than rely on a ''proxy'' for the import limits.

891. Our experience is that sellers located in RTOs/ISOs typically do not need to rely on a SIL study in performing the screens, and transmission-owning utilities in RTOs/ISOs typically do not prepare or submit such studies. Accordingly, staggered filings for sellers in RTOs/ISOs may not be necessary for purposes of data availability. Nevertheless, we will retain the staggered filing deadlines for all regions for consistency and to avoid any confusion in this regard. If a particular seller that is located in an RTO/ISO finds that it needs import data in order to complete its market power analysis, we expect the RTO/ISO to assist such sellers if requested.

892. In response to MidAmerican's suggestion that the Commission allow adequate time between the date that all data is available and the date that a region's analyses are due, we will schedule the updates to be filed in December (12 months after the study year), and June (18 months after the study year). We note that studies due in

[1026] In this regard, we note that preparation of multiple market power analyses is likely less burdensome and less expensive than what would otherwise be required under cost-based regulation which can result in extended administrative litigation to determine the just and reasonable rate.

[1027] Concerning power marketers that may not own or control generation assets in any region, we will require the submission of a filing explaining why the seller meets the Category 1 criteria, as discussed above. Power marketers must submit such a filing with the first scheduled geographic region in which they make any sales.

[1028] If the Commission has not processed a particular SIL study before six months have passed and non-transmission owning entities must file their updated market power analyses, then those entities should rely on the filed SIL study. If the initial SIL study subsequently changes, the Commission will make conforming adjustments as needed.

December and June may be filed anytime during the applicable month. Such a schedule will allow adequate time for the data to be available (at least 6 weeks after EIA Forms 860 and 861 become public) and the analyses to be completed.

893. In response to commenters' requests that the Commission extend the time until the first analyses are due, we will commence the schedule in December 2007. The Commission believes this will provide adequate notice and time to prepare the analyses. In addition, we clarify that sellers that otherwise would have been required to file an updated market power analysis before the effective date of this rule should submit their updated market power analyses in accordance with past orders directing them to do so. Starting with the effective date of this rule, sellers should submit their updated market power analyses in accordance with the schedule set forth in Appendix D.

894. We also agree with the suggestion of APPA/TAPS to extend the period for intervenors to comment on the updates. We agree that extending the comment period will allow intervenors a better opportunity to review and comment on filings, especially considering the large number of filings that will be submitted at one time. For that reason, the Commission will establish a 60-day comment period for updated market power analyses. Further, we adopt the NOPR proposal to require that with each new application and updated market power analysis, the seller must list in an appendix, among other things, all affiliates that have market-based rate authority and identify any generation assets owned or controlled by the seller and any such affiliate. In addition, we extend this obligation to relevant change in status notifications.[1029] We believe that requiring the submission of such data will provide the Commission with more accurate and up-to-date information about each corporate family and will address some of our concerns regarding confusion that has occurred with respect to corporate families and, in particular, what sellers are authorized to transact at market-based rates in each corporate family.

895. Accordingly, the appendix must list all generation assets owned (clearly identifying which affiliate owns which asset) or controlled (clearly identifying which affiliate controls which asset) by the corporate family by balancing authority area, and by geographic region, and provide the in-service date and nameplate and/or seasonal ratings by unit. As a general rule, any generation assets included in a seller's or a seller's affiliate's market study should be listed in the asset appendix. We find that the in-service date and nameplate and/or seasonal ratings help identify and provide the Commission and market participants with critical market information. In addition, the appendix must reflect all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family and the location of such facilities.

896. In response to Duke, we clarify that CEII data is more detailed than ''simply [giving] the general location of the critical infrastructure.'' [1030] As the location of the facilities listed in the appendix need only include the balancing authority area and geographic region (see sample appendix attached as Appendix B) in which they are located, we do not anticipate that any CEII will be disclosed.

F. MBR Tariff

Commission Proposal

897. In the NOPR, the Commission proposed to adopt a market-based rate tariff of general applicability (MBR tariff), applicable to all sellers authorized to sell electric energy, capacity or ancillary services at wholesale at market-based rates, as a condition of market-based rate authority. The MBR tariff, as proposed, would require each seller to comply with the applicable provisions of the market-based rate regulations to be codified at 18 CFR Part 35, Subpart H. The Commission proposed that each seller would be required to list on the MBR tariff the docket numbers and case citations, where applicable, of any proceedings where the seller received authorization to make sales of energy between affiliates or where its market-based rate authority was otherwise restricted or limited.

898. The Commission explained that not all of the provisions of the proposed regulations may be applicable to all sellers. For example, a seller may not wish to offer ancillary services under the tariff. The Commission sought comments regarding whether a placeholder should be reserved in the MBR tariff for the seller to indicate those parts of the regulations that are not applicable to it.

899. The Commission stated that this streamlining effort is not intended to reduce the flexibility of sellers and customers in negotiating the terms of individual transactions. The Commission noted that sellers would continue to negotiate the terms and conditions of sales entered into under their MBR tariff, and the terms and conditions of those underlying agreements and the transaction data would be reflected in the quarterly EQRs. The Commission stated that if sellers wish to offer or require certain ''generic'' terms and conditions that in the past were contained in their market-based rate tariff, they may place customers on notice of such requirements by including such information on a company Web site and include any related provisions in individual transaction agreements. The Commission explained its desire that the MBR tariff reflect, in a consistent manner, only those matters that are required to be on file.[1031]

900. Further, rather than each entity having its own MBR tariff, which can result in dozens of tariffs for each corporate family with potentially conflicting provisions, the Commission proposed that each corporate family have only one tariff, with all affiliates with market-based rate authority separately identified in the tariff.[1032] The Commission stated that this would reduce the administrative burden and confusion that occurs when there are multiple, and potentially conflicting, tariffs in a single corporate family, and would allow the Commission and customers to know what sellers are in each corporate family.

1. Tariff of General Applicability

Comments

901. Several commenters do not support the adoption of a tariff of general applicability. Allegheny argues that ''the Commission is without legal authority to impose a one-size-fits-all market-based rate tariff.'' [1033] It argues that the Commission has made no finding of undue discrimination and is not proposing to act under FPA section 206, and asserts that administrative efficiency is an insufficient justification to impose a standardized tariff on market-based rate sellers. Similarly, FirstEnergy asserts that requiring a uniform MBR tariff would impose undue administrative burdens on sellers, as each would have to make a compliance filing modifying its currently effective tariff and would also

[1029] Relevant change in status notifications would include, for example, the addition of new facilities, but not a name change.

[1030] 18 CFR 388.113(c)(1)(iv).

[1031] NOPR at P 163.

[1032] *Id.* at P 164.

[1033] Allegheny at 20.

have to expand its compliance program to confirm that its tariff was in conformance with the uniform tariff.

902. Xcel states that the Commission has not made clear its basis for and expected benefit from a *pro forma* tariff. Xcel suggests that, if it is adopted, then the Commission should describe any limitations on a seller's market-based rate authority, in addition to identifying any docket numbers where they were imposed.[1034]

903. Similarly, Avista Corporation believes that all of the terms and conditions of a tariff should be included in one easily accessible place. Requiring that certain terms and conditions be posted on a company Web site, rather than the tariff, is bound to cause unnecessary confusion as to which terms and conditions apply, and will increase the burden on both the utilities to notify, and customers to remain apprised, of when those terms and conditions change.[1035] Additionally, FirstEnergy states that a process by which a seller places customers on notice of such terms and conditions beyond the minimum by including such information on a company Web site, and including related provisions in individual transaction agreements, would be cumbersome at best, and would deprive sellers and customers of the benefit of having the ''generic'' terms and conditions in one document.[1036]

904. Commenters who responded to the question of whether a placeholder should be reserved in the tariff to indicate parts of the regulations that are not applicable to the seller, support the idea of a placeholder.[1037]

905. Mirant notes that the sample MBR tariff attached to the NOPR did not provide for specific RTO/ISO ancillary service products and states that it is unclear how the Commission would identify which seller under the corporate tariff is permitted to sell the specific ancillary services traded in each region. Mirant asks whether the Commission would require each seller of ancillary services to maintain an ancillary services tariff on file with the Commission. Mirant further notes that some sellers not located in an RTO/ISO have been granted authorization to sell ancillary services at market-based rates if they post those services on their Web sites and suggests that the requirement that sellers maintain such a Web site would have to be cross-referenced in the corporate tariff.

906. EEI states that companies with operations in multiple markets may need to tailor their market-based rate tariffs to reflect the particular circumstances of each market. This will be true for RTO and ISO markets as well as non-RTO markets. In each of these cases, participants in the markets typically must agree to abide by specific market terms and conditions that may need to be reflected in the tariff. Therefore, EEI encourages the Commission to allow each company to file multiple tariffs, as may be necessary to reflect these market differences.[1038]

907. Regarding the timing of tariff implementation, MidAmerican comments that the Commission should apply the new tariff prospectively only to future transactions, and urges that existing tariffs should be unaffected until existing transactions expire. MidAmerican observes that if existing tariffs containing terms and conditions are replaced by the proposed generic tariff, then neither the new tariff nor the existing service agreements will reflect the terms and conditions of ongoing transactions.

908. ELCON supports the proposed MBR tariff, believing that it will be more customer-friendly. APPA/TAPS agree, stating that a pro forma tariff will help by addressing variations in MBR tariffs that increase transaction costs by creating potential confusion about applicable terms and conditions.[1039] A number of commenters find some merit in the concept of the MBR tariff, but request clarifications or revisions.[1040] Some of these entities comment that companies with operations in multiple markets may need to tailor their tariffs to reflect the particular circumstances of each market, and state that participants in organized markets typically must agree to abide by specific terms that may need to be reflected in their tariffs.

909. Indianapolis P&L asserts that any restrictions on market-based rate authority should be in a tariff, rather than in Commission orders. It believes that ''converting concepts (*e.g.*, all sales in a control area will be mitigated) into precise contract-worthy terms and conditions can be very difficult'' and argues that the best way to prevent misunderstandings between parties is to have ''precise, transparent and, publicly-available language in a tariff explaining the precise conditions on an entity's market-based rate authority.''[1041] Indianapolis P&L further warns that ''having restrictions on an entity's market-based rate authorization contained in a tariff only through cross-reference to a Commission order may run afoul of the FPA requirement that rates be 'on file' with the Commission.''[1042]

910. Constellation seeks clarification that a seller that has received waiver from the code of conduct need not report in its MBR tariff that the affiliate restrictions in proposed § 35.39 do not apply to it. Alternatively, Constellation suggests that the Commission allow sellers to list the appropriate docket numbers in which the Commission has granted waivers of the code of conduct or provide a place to indicate that the provisions are not applicable. Constellation notes that many market-based rate sellers have included provisions in their tariffs regarding reassignment of transmission capacity and sale of firm transmission rights, congestion contracts, or fixed transmission rights (as a group, ''FTRs''), and requests that the Commission either provide for inclusion of such provisions in the MBR tariff or state affirmatively that they will not be required.

Commission Determination

911. In the NOPR, the Commission explained that it was acting pursuant to sections 205 and 206 of the FPA in proposing to amend its regulations to govern market-based rate authorizations for wholesale sales of electric energy, capacity and ancillary services by public utilities, ''including modifying all existing market-based rate authorizations and tariffs so they will be expressly conditioned on or revised to reflect certain new requirements proposed herein.''[1043] Section 205 of the FPA requires that all rates for sales subject to our jurisdiction, and all rules and regulations pertaining to such rates, be just and reasonable. Section 206 of the FPA provides that, when the Commission finds that a rate or a rule, regulation or practice affecting a rate, is unjust or unreasonable, the Commission shall determine the just and reasonable rate, rule or regulation and order it so.

912. Based on careful consideration of the comments received, the Commission agrees that complete uniformity of market-based rate tariffs is not necessary. However, pursuant to our

[1034] Xcel at 17.

[1035] Avista at 10–12.

[1036] First Energy at 27–31.

[1037] Avista at 10; MidAmerican at 33 (suggesting that the placeholder could be included as an attachment to each seller's tariff in order to preserve the generic nature of the tariff itself); Progress Energy at 19.

[1038] EEI at 49.

[1039] EEI counters APPA/TAPS, asserting that each seller's MBR tariff in a given market is fully available to market participants, so there should be no confusion. EEI reply comments at 30–31.

[1040] FirstEnergy at 27–29; Constellation at 27–29; Progress Energy at 19–23.

[1041] Indianapolis P&L at 15.

[1042] *Id.*

[1043] NOPR at P 1.

authority under sections 205 and 206, we conclude that the lack of consistent tariff form and content has hampered our ability to manage the market-based rate program in an efficient manner and has introduced uncertainty for potential customers. We find that continuing to allow basic inconsistencies in the market-based rate tariffs on file with the Commission is unjust and unreasonable. Nevertheless, we find that we can achieve our goal without imposing a uniform tariff requirement on all sellers by, instead, requiring that all sellers revise their market-based rate tariffs to contain certain standard provisions, as discussed below.

913. We believe the approach we adopt here addresses the concerns of commenters that the Commission not impose a one-size-fits-all approach while, at the same time, presenting a uniform set of required provisions that will provide adequate certainty and will be more customer friendly. In addition, we believe that allowing sellers to include seller specific terms and conditions in their market-based rate tariffs will offer a greater degree of transparency and serve customers by providing for the opportunity to have all terms and conditions identified and in one place. As Progress Energy asserts, ''[g]reater consistency of tariffs within the industry * * * will not only reduce customer confusion, it also will reduce the administrative burden of those responsible for the implementation and administration of the tariff.'' [1044]

914. Accordingly, in this Final Rule, we adopt two standard ''required'' provisions that each seller must include in its market-based rate tariff: a provision requiring compliance with the Commission's regulations and a provision identifying any limitations and exemptions regarding the seller's market-based rate authority.

915. In particular, with regard to compliance with the Commission's regulations, we will require each seller to include the following provision in its market-based rate tariff:

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

916. We also will require that the seller include a provision identifying all limitations on its market-based rate authority (including markets where the seller does not have market-based rate authority) and any exemptions from, or waivers of, or blanket authorizations under the Commission's regulations that the seller has been granted (such as exemption from affiliate sales restrictions; waiver of the accounting regulations; blanket authority under Part 34 for the issuances of securities and liabilities, etc.), including cites to the relevant Commission orders.

917. In addition to the required tariff provisions, we also will adopt a set of standard provisions (which we reference herein as ''applicable provisions'') that must be included in a seller's market-based rate tariff to the extent that they are applicable based on the services provided by the seller. For example, if the seller's sales under its market-based rate tariff are subject to mitigation, it must include the standard provision governing mitigated sales. Similarly, if the seller makes sales of certain ancillary services in certain RTOs/ISOs, or if it makes sales of ancillary services as a third-party provider, it must include the standard ancillary services provisions, as applicable.

918. Attached hereto as Appendix C is a listing of the standard required provisions and the standard applicable provisions. The Commission will post these provisions on its web site and will update them as appropriate.

919. In addition, as discussed more fully below, we will permit sellers to list in their market-based rate tariffs additional seller-specific terms and conditions that go beyond the standard provisions set forth in Appendix C.

920. As Constellation observes, the uniform MBR tariff proposed in the NOPR did not provide for sellers to offer reassignment of transmission capacity or FTRs. As revised in this Final Rule, Appendix C does not contain a standard provision for the reassignment of transmission capacity. The Commission believes that, although these items have historically been offered in the context of sales of electric energy and capacity, they are transmission-related rather than generation services. Accordingly, the Commission has made provision for reassignment of transmission capacity in the revised OATT, as discussed in Order No. 890.[1045] Thus, we state affirmatively here that provisions concerning the reassignment or sale of transmission capacity or FTRs are not required to be included in a seller's market-based rate tariff, nor is it appropriate to include transmission-related services in the seller's market-based rate tariff. Sellers seeking to reassign transmission capacity should adhere to the provisions of Order No. 890 [1046] and should revise their market-based rate tariffs to remove provisions governing these services at the time they otherwise revise their tariffs to conform them to the standard provisions discussed herein.

921. Regarding FTRs and, incidentally, virtual trading,[1047] we note that Commission-approved market rules for RTOs/ISOs address resales of FTRs and virtual trading to ensure that no market power is exercised in such trades. In addition, sellers engaging in these activities sign a participation agreement with RTOs/ISOs which require them to abide by those market rules. Hence, the approval of the market rules in conjunction with approval of the generic participation agreement by the Commission constitutes authorization for public utilities to engage in the resale of FTRs and virtual transactions, and no separate authorization is required under the FPA. The Commission's monitoring of the effectiveness of the market rules and oversight of participants engaging in FTR resales and virtual trading in the RTO/ISO markets provide sufficient protections against the exercise of market power. Nevertheless, if the Commission concludes in the future that a separate section 205 authorization would better enable us to ensure that FTR resales or virtual trading do not result in unjust and unreasonable

[1044] Progress Energy at 19–20.

[1045] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 814–816 & n.496.

[1046] *Id.* at P 816.

[1047] Virtual trading involves sales or purchases in an RTO/ISO day-ahead market that do not go to physical delivery. For example, virtual bidding allows entities that do not serve load to make purchases in the day-ahead market. Such purchases are subsequently sold in the real-time spot market. Likewise, entities without physical generating assets can make power sales in the day-ahead market that are subsequently purchased in the real-time market. By making virtual energy sales or purchases in the day-ahead market and settling these positions in the real-time, any market participant can arbitrage price differences between the two markets. For example, a participant can make virtual purchases in the day-ahead if the prices are lower than it expects in the real-time market, and then sell the purchased energy back into the real-time market. The result of this transaction would be to raise the day-ahead price slightly due to additional demand and, thus, improve the convergence of the day-ahead and real-time energy prices due to additional supply in the real-time. Virtual trading is not limited to entities without assets. For example, generators or loads that prefer to transact at the real-time price may use virtual trading to accomplish this without having to under-schedule load or withhold generation from the day-ahead market by submitting matching virtual trades.

wholesale rates, the Commission may change the filing requirements for engaging in these activities.[1048]

922. To the extent that individual companies within a corporate family need or desire a tariff separate from their affiliates, the Commission will allow this, as discussed below. Although EEI asserts that participants in organized markets may need to meet the requirements of various organized markets, EEI offers no specific examples in this regard. Nevertheless, we believe that our action to replace the uniform MBR tariff proposed in the NOPR with standard provisions that we will require to be included in a seller's market-based rate tariff and the allowance of seller specific terms and conditions in the market-based rate tariff should meet the needs of all sellers with market-based rate authority.

923. We will require all market-based rate sellers to make section 206 compliance filings to modify their existing tariffs to include the standard required provisions set forth in Appendix C as well as any of the standard applicable provisions. These compliance filings are to be made by each seller the next time the seller proposes a tariff change, makes a change in status filing, or submits an updated market power analysis (or a demonstration that Category 1 status is appropriate) in accordance with the schedule in Appendix D.

924. One of the required standard provisions (the compliance with Commission regulations provision) states that failure to comply with the applicable provisions of the regulations adopted in this Final Rule or with any Commission orders concerning a seller's market-based rate authority will constitute a violation of the seller's tariff. As provided in this Final Rule, the regulations at 18 CFR Part 35, Subpart H will become effective 60 days after publication of this Final Rule in the **Federal Register**. Accordingly, this provision will be considered part of each seller's market-based rate tariff effective as of the effective date of this Final Rule. As noted above, all sellers will be required to amend their market-based rate tariffs to include the required standard provisions, as well as the required applicable provisions, either at the time that they file any other amendment to their current tariffs, when they report a change in status, or when they file their updated market power analysis, whichever occurs first. However, regardless of the date on which sellers make their compliance filing, the provision providing that failure to abide by the regulations will constitute a tariff violation will be considered part of each seller's current market-based rate tariff as of 60 days after the date of publication of this Final Rule in the **Federal Register**.

2. Placement of Terms and Conditions

Comments

925. In the NOPR, the Commission observed that the purpose of an MBR tariff of general applicability is not to direct the terms and conditions of particular sales but to ensure that the tariff on file reflects in a consistent manner only those matters that are required to be on file, namely, the identity of the seller(s), the docket number(s) of the market-based rate authorization, the seller's requirement to follow the conditions of market-based rate authorization contained in the proposed regulations, and that the rates, terms and conditions of any particular sale will be negotiated between the seller and individual purchasers. The Commission stated that sellers could offer other ''generic'' terms and conditions as information on a company Web site.

926. In response, several commenters state that requiring companies to move generic terms and conditions to a company Web site, or to replicate them in individual agreements or rely on Commission orders, would be confusing and/or overly cumbersome.[1049] Avista and FirstEnergy believe that all of the terms and conditions of a tariff should be in one easily accessible place; otherwise, sellers and customers would be deprived of the benefit of having them in one document. According to FirstEnergy, this ''would be contrary to the goal of establishing a 'customer-friendly tariff' as contemplated in the NOPR.'' [1050] Further, FirstEnergy states that the fact that the Commission may not review individualized commercial terms included in tariffs does not make it unjust and unreasonable for sellers to include such terms in their tariffs; thus, there is no basis for the Commission to exercise its authority under FPA § 206 to require changes to existing market-based rate tariffs. However, Progress Energy agrees with the Commission that commercial terms and conditions for sales under the MBR tariff should not be filed for Commission review.

Commission Determination

927. As discussed above, we find consistency of standard market-based rate tariff provisions to be essential, and we modify the proposal in the NOPR by adopting a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff, but we do not adopt the NOPR proposal that all sellers adopt the uniform MBR tariff of general applicability set forth in the NOPR. After careful consideration of the comments, we also will not adopt the NOPR proposal that sellers offer other generic terms and conditions as information on a company Web site. We agree with commenters as to the benefits to sellers and customers of having all terms and conditions relevant to a seller's market-based rate power sales available in one document. Thus, we will permit sellers to list in their market-based rate tariffs additional terms and conditions that go beyond the standard provisions required in Appendix C (with the exception of transmission-related services, as discussed above), as modified in this Final Rule. As has been our practice in many instances, we will not evaluate the justness and reasonableness of such additional provisions, but will allow them to be included in the market-based rate tariff that is on file with the Commission. Our reasoning is that such additional provisions are presumptively just and reasonable. A seller granted market-based rate authority has been found not to have, or to have adequately mitigated, market power; thus, if a customer is not satisfied with the terms and conditions offered by a seller, the customer can choose to purchase from a different supplier.

3. Single Corporate Tariff

Comments

928. ELCON supports the NOPR proposal that each corporate family have one tariff on file, stating that it will lead to better transparency regarding what each seller in a corporate family owns or controls. APPA/TAPS agree, commenting that a single corporate tariff addresses recurring problems with determining exactly who is affiliated with whom.[1051] Sempra agrees in

[1048] To the extent that this position departs from our holding in *California Independent System Operator, Inc.,* 89 FERC ¶ 61,153 at 61,435–36 (1999) (requiring, among other things, that all public utility resellers of FTRs file a rate schedule for authorization to make resales) we note that that analysis rested on Order No. 888's filing requirements for resales of transmission capacity. As Order No. 890 has modified the filing requirements with respect to reassignments of transmission capacity (in addition to the reasons cited above) we find it appropriate not to require a separate rate schedule for FTRs or virtual trading at this time.

[1049] Avista at 10–12; Indianapolis P&L at 14–15; FirstEnergy at 27–31.

[1050] FirstEnergy at 29.

[1051] EEI disagrees, contending that, since companies already disclose affiliations in their

Continued

general that the single tariff structure should eliminate confusion that results when entities within the same corporate family have tariffs with terms that differ.

929. However, a number of commenters raise potential implementation issues and believe that having all entities in a corporate family selling under the same tariff should be optional and not mandatory.[1052] Several of these commenters state that the Commission has not demonstrated the need for a single corporate tariff and believe that the added burden of implementation would outweigh any benefits.[1053]

930. Some of the problems with the single corporate tariff proposal identified by commenters include the following:

- The proposal does not make sense for diversified energy companies with a variety of non-utility generator or power marketer affiliates because it would require increased regulatory and legal coordination among affiliates;
- The burden of replacing multiple market-based rate tariffs with one umbrella tariff would be significant, requiring amendment and re-execution of many documents with many trading counterparties, as well as extensive changes to the existing quarterly reporting process;
- A single tariff listing all affiliates could create confusion regarding which affiliates may be bound by certain executed service agreements, or which terms and conditions apply to certain affiliates;
- Confusion would result when trying to create a single tariff per corporate family when sellers can have multiple corporate families; listing the same seller on the MBR tariffs of multiple corporate groups would not improve transparency; and
- Given that some sellers' upstream ownership can include multiple investors, passive investors, and limited partners, the proposal could impose a filing requirement on entities that have only a passive role and may not otherwise be engaged in the energy business.

931. Several commenters assert that, while they support the objective of simplifying tariff administration, the Commission has not considered the administrative and commercial ramifications of mandating one tariff per family. For instance, Duke cites the possibility that any seller under the corporate tariff could be sued for an affiliate's alleged breach, and the complications of Company A selling Subsidiary X to Company B and the status of X's sales under Company A's tariff. Mirant questions how the sale of a subsidiary's MBR tariff to a non-affiliate would be handled, given that the tariffs are assets that can be bought and sold. In a related comment, Ameren asks for which company or companies would the tariff be a jurisdictional facility for purposes of FPA section 203. EPSA and Sempra request clarification regarding how an enforcement action would be affected by the presence of other members of a corporate family on the same tariff, and Ameren seeks clarification on the effect of a revocation of market-based rate authority of only some companies in a corporate family. MidAmerican suggests that, since different affiliates within a corporate family may have authority to offer different services, a service schedule to the tariff should specify the products that each affiliate is authorized to offer and any restrictions or limitations on a seller's market-based rate authorization. Morgan Stanley notes that, in many cases, the ''parent'' is not a jurisdictional entity or is a holding company, and recommends requiring each corporate family to designate a lead company that will submit its filing and those of its affiliates, rather than specifically appointing the ''parent corporation'' as the filing entity. Duke urges the Commission to consider what legal means would be required to ensure that the tariff is legally a separate and severable tariff for each member of a family.

932. Further, commenters state that there are transitional issues that the Commission should consider, such as whether existing tariffs will be superseded or cancelled and all existing service agreements migrated to the joint tariff; which corporate entity would be required to file and maintain the MBR tariff; and the extent to which affiliates may have to file separate quarterly reports due to the fact that the responsible employees are not shared (*e.g.*, regulated versus unregulated merchant employees).

933. In reply comments, EPSA reiterates its opposition to a mandatory single corporate tariff, urging the Commission to abandon the proposal because it ''poses major practical obstacles for corporate parents that own vastly differing affiliates.''[1054] EPSA contends that the Commission's premise for adopting the proposal, *i.e.*, entities within a corporate family can have conflicting tariff provisions, is mooted by the adoption of a standardized tariff. In addition, EPSA echoes implementation concerns raised by other parties, in particular: (1) The situation where a seller is a member of two corporate families; and (2) increased regulatory burden from frequent tariff amendments each time ownership changes and corporate affiliations are terminated or created.

934. Indianapolis P&L argues that affiliates should be permitted to maintain separate market-based rate tariffs for many of the reasons already cited. In addition, it contends that consolidation will increase the burden on many entities by requiring increased regulatory and legal coordination between affiliates. Whereas many utilities presently separate their utility and non-utility operations in part to comply with Commission regulations, Indianapolis P&L asserts that mandating a single tariff per corporate family would necessarily require utility and non-utility affiliates to operate in closer coordination. FirstEnergy agrees, stating that ''[t]he Commission should not expect franchised public utilities with captive customers to market power totally independently of their affiliates where they are all required to sell power to wholesale purchasers under the same tariff.''[1055]

935. Finally, some commenters state that the Commission's concerns can be satisfied through means other than a single tariff per corporate family. Duke recommends allowing affiliated utilities to operate with separate but uniform tariffs while posting on their corporate Web sites a centralized list of each of the affiliates' market-based rate tariffs. Similarly, Progress Energy suggests requiring sellers to use the standardized tariff but having them include a section identifying all affiliates with market-based rate authority and any restrictions on that authority.

Commission Determination

936. We will modify the NOPR proposal and allow sellers to elect whether to transact under a single market-based rate tariff for an entire corporate family or under separate tariffs. The benefits that the Commission hoped to realize by requiring all corporate families to consolidate their operations under one tariff will be achievable by other means, namely, by

individual market-based rate filings and are separately subject to the Commission's affiliate transactions rules, any confusion about affiliations does not justify a single tariff requirement. EEI reply comments at 30–31.

[1052] *See*, *e.g.*, EPSA at 41; Duke at 45–48; MidAmerican at 33–35; FirstEnergy at 27–31; Constellation at 27–29; Progress Energy at 19–23; EEI at 49. Cogentrix also expresses reservations about requiring a single corporate tariff. *See* Cogentrix/Goldman at 6–8.

[1053] *See*, *e.g.*, Mirant at 6–10; FirstEnergy at 27–31.

[1054] EPSA reply comments at 3–4.

[1055] FirstEnergy at 30.

having each individual seller revise its existing market-based rate tariff to include the standard tariff provisions we require in this Final Rule and by maintaining up-to-date information on sellers' affiliates through the submission of asset appendices.[1056]

937. For the benefit of those sellers that choose a single corporate tariff, we clarify that each seller should continue to report its own transactions using the docket number under which it initially received market-based rate authority.

G. Legal Authority

1. Whether Market-Based Rates Can Satisfy the Just and Reasonable Standard Under the FPA

Comments

938. A number of commenters challenge the Commission's authority to adopt a market-based rate regime.[1057] State AGs and Advocates contend that the courts have never actually reviewed the Commission's market-based rate program and found that it satisfies the FPA. They contend that the Commission in the NOPR cited *dictum* in *Louisiana Energy and Power Authority* v. *FERC*,[1058] noting that the petitioner in that case did not challenge the Commission's general policy of permitting market-based rates in the absence of market power. They further argue that the D.C. Circuit in *Elizabethtown Gas Company* v. *FERC*,[1059] relied on *dictum* in a prior gas case to the effect that, where markets are competitive, it is ''rational'' to assume that a seller will make ''only a normal return on its investment.'' State AGs and Advocates then criticize the D.C. Circuit's opinion, arguing that ''this sort of judicial economic theorizing does not constitute either the substantial evidence required to support orders of this Commission under the [FPA], or the 'empirical proof' required by the courts when an agency attempts to substitute competition for statutorily required regulation.'' [1060]

939. NASUCA similarly questions the Commission's reliance on *Elizabethtown Gas* as the legal foundation for its market-based rate regime. NASUCA suggests that the Supreme Court's decision in *MCI* v. *AT&T*,[1061] casts considerable doubt on the vitality of *Elizabethtown Gas* and cases that follow its apparent endorsement of market-based rates that did not consider the statutory filing issues found crucial in *MCI*. NASUCA also notes that, in another case the Commission relied on, *Mobil Oil Exploration* v. *United Distribution Co.*,[1062] the Supreme Court cited to *FPC* v. *Texaco*, where it held that just and reasonable rates cannot be determined solely by reference to market prices.[1063]

940. Some commenters argue that a finding that competitive markets exist is a prerequisite to relying upon market-based rate authority to satisfy the mandates of the FPA.[1064] Industrial Customers contend that the Commission may rely on market-based rate authority to produce just and reasonable rates if it finds that a competitive market exists and the seller lacks or has adequately mitigated market power. They submit that the duty to determine that a competitive market exists is separate and independent of the determination that a seller lacks, or has adequately mitigated, market power.

State AGs and Advocates contend that the market-based rate program offers no way to monitor whether existing competition results in just and reasonable rates, nor a way to check rates if it does not.[1065]

941. In reply, PNM/Tucson argues that the Commission need not entertain attacks on the existence of competitive power markets and the legality of market-based rates under the FPA, as they constitute collateral attacks on recent Commission decisions and the *Lockyer* opinion, and because a theoretical debate on the subject is beyond the scope of this rulemaking proceeding. PNM/Tucson asserts that those cases found that market-based rates are permissible by law and urges the Commission to reject any attacks on market-based rates generally.[1066]

942. Financial Companies respond to State AGs and Advocates' assertion that the Commission should suspend or revoke all market-based rates and return to cost-of-service ratemaking by commenting that the complaining parties mischaracterize the state of the wholesale market. Financial Companies enumerate the ''myriad of approval, reporting and other obligations'' [1067] that constitute the Commission's oversight and point out that ISOs and RTOs provide another layer of market monitoring and mitigation. They state that it is preferable to shape market power remedies addressing specific circumstances than to revoke market-based rate tariffs for all sellers.

Commission Determination

943. The Commission rejects arguments that it has no authority to adopt market-based rates or that the market-based rate program it is adopting in this rule does not comply with the FPA. The Supreme Court has held that ''[f]ar from binding the Commission, the FPA's just and reasonable requirement accords it broad ratemaking authority.* * * The Court has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula in general. * * *'' [1068] It is settled law that market-based rates can satisfy the just and reasonable standard of the FPA, as most recently reaffirmed by the Ninth Circuit in *Lockyer* and *Snohomish*,[1069] and the court in *Lockyer* expressly denied a ''facial challenge to the market-based [rate] tariffs,'' as discussed below.

944. In the *Lockyer* court's analysis of the Commission's market-based rate authority, the Ninth Circuit cited the Supreme Court's determination in *Mobil Oil Exploration.* It also noted that the use of market-based rate tariffs was first approved (by the courts) as to sellers of natural gas in *Elizabethtown Gas,* then as to wholesale sellers of electricity in *LEPA.*

945. Commenters have also argued that the proposed rule impermissibly relies solely on the market to determine just and reasonable rates, as was the case in *Texaco.* We reject these arguments as well.

946. In *Texaco,* the Supreme Court found that the Natural Gas Act (NGA) permits the indirect regulation of small-producer rates.[1070] The Supreme Court

[1056] The asset appendix is discussed above in Implementation Process.

[1057] *E.g.*, State AGs and Advocates at 3–13, 18–28, 38–40; NASUCA at 33–37.

[1058] 141 F.3d 364, 365 (D.C. Cir. 1998) (*LEPA*).

[1059] 10 F.3d 866, 870 (D.C. Cir. 1993) (*Elizabethtown Gas*).

[1060] State AGs and Advocates at 8–9.

[1061] 512 U.S. 218 (1994) (*MCI*).

[1062] 498 U.S. 211 (1991).

[1063] 417 U.S. 380, 397 (1974).

[1064] Industrial Customers at 3–12; NRECA at 6–10; State AGs and Advocates reply comments at 17–22.

[1065] State AGs and Advocates reply comments at 18–19, citing *Farmers Union* (finding reliance on existing competition, with no monitoring or mitigation, unacceptable).

[1066] PNM/Tucson reply comments at 3–4 (citing *Lockyer* and the underlying Commission orders, *State of California, ex rel. Bill Lockyer* v. *British Columbia Power Exchange Corp.*, 99 FERC ¶ 61,247, *order on reh'g*, 100 FERC ¶ 61,295 (2002)).

[1067] Financial Companies reply comments at 10.

[1068] See *Mobil Oil Exploration* v. *United Distribution Co.,* 498 U.S. 211, 224 (1991) (Mobil Oil Exploration), citing *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *FPC* v. *Natural Gas Pipeline Co.,* 315 U.S. 575, 586 (1942); Permian Basin Area Rate Cases, 390 U.S. 747, 776–77 (1968) (Permian); Texaco; *Mobil Oil Corp.* v. *FPC,* 417 U.S. 283, 308 (1974).

[1069] *Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 471 F.3d 1053 (9th Cir. 2006) (Snohomish).

[1070] Cases under the NGA and the FPA are typically read *in pari materia. See, e.g., FPC* v. *Sierra Pacific Power Company,* 350 U.S. 348, 353

Continued

explained that ''[t]he Act directs that all producer rates be just and reasonable but it does not specify the means by which that regulatory prescription is to be attained. That every rate of every natural gas company must be just and reasonable does not require that the cost of each company be ascertained and its rates fixed with respect to its own costs.'' [1071] The Supreme Court noted that it had sustained rate regulation based on setting area rates that were based on composite cost considerations, citing its decision in *FPC* v. *Hope Natural Gas Co.* [1072] The Supreme Court further explained, with respect to the prior area rate cases, ''we recognized that encouraging the exploration for and development of new sources of natural gas was one of the aims of the Act and one of the functions of the Commission. The performance of this role obviously involved the rate structure and implied a broad discretion for the Commission.'' [1073] Quoting *Permian Basin*, the Supreme Court added that ''[i]t follows that ratemaking agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.' '' [1074]

947. The *Texaco* Court further stated that ''the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates mandated by the Act.'' [1075] But, ''[t]his does not mean that the market price of gas would never, in an individual case, coincide with just and reasonable rates or not be a relevant consideration in the setting of area rates.'' [1076]

948. In *Elizabethtown Gas,* a decision relying on *Texaco,* the D.C. Circuit addressed a Commission order approving a restructuring settlement under which Transcontinental Gas Pipeline Corporation (Transco) would no longer sell gas bundled with transportation, but would sell gas at the wellhead or pipeline receipt point, to be transported as the buyer sees fit. The sales would be market-based (negotiated) and the rates for transportation on Transco's system would be cost-of-service based. In approving the settlement, the Commission had ''determined that Transco's markets are sufficiently competitive to preclude the pipeline from exercising significant market power in its merchant function and to assure that gas prices are 'just and reasonable' within the meaning of the NGA section 4.'' [1077] The Commission also ''authorized Transco in advance 'to establish and to change' individually negotiated rates free of customer challenge under section 4 of the NGA; the 'only further regulatory action' possible under the settlement is the Commission's review of Transco's prices under section 5 of the Act, upon the Commission's own motion or upon the complaint of a customer that is not a party to the settlement.'' [1078]

949. In *Elizabethtown Gas,* the D.C. Circuit upheld the Commission's approval of market-based pricing, holding that ''nothing in *FPC* v. *Texaco* precludes the FERC from relying upon market-based pricing.'' [1079] The D.C. Circuit explained that in *Texaco,* the Commission had failed to even mention the ''just and reasonable'' standard and appeared to apply only the ''standard of the marketplace'' in reviewing the reasonableness of the rate (which the Supreme Court had found to be unacceptable). Thus, the D.C. Circuit explained with approval, ''the FERC has made it clear that it will exercise its section 5 authority (upon its own motion or upon that of a complainant) to assure that a market (*i.e.*, negotiated) rate is just and reasonable.'' [1080]

950. The D.C. Circuit noted that the Commission had specifically found that Transco's markets are sufficiently competitive to preclude it from exercising significant market power. It further noted that the Commission had explained that Transco would be providing comparable transportation for all gas supplies and that ''adequate divertible gas supplies exist'' to assure that Transco would have to sell at competitive prices. Thus, the D.C. Circuit concluded that Transco would not be able to raise its price above the competitive level without losing substantial business. ''Such market discipline provides strong reason to believe that Transco will be able to charge only a price that is 'just and reasonable' within the meaning of section 4 of the NGA.'' [1081]

951. Likewise in *LEPA,* the D.C. Circuit affirmed the Commission's approval of an application by Central Louisiana Electric Company (CLECO) to sell electric energy at market-based rates. The D.C. Circuit found reasonable the Commission's conclusion that there are no market power considerations that should bar CLECO's application to sell at market-based rates. It also found reasonable the Commission's conclusion that even if CLECO had participated in oligopolistic behavior in the past, the Commission's new open access transmission rules had transformed the competitive environment. The D.C. Circuit noted that ''competitors outside the current, alleged oligopoly will now be able to transmit power into CLECO's territory on nondiscriminatory terms.'' [1082] Thus, according to the D.C. Circuit, the Commission reasonably predicted that it was ''unlikely that 'energy suppliers will decline to participate in the emerging competitive markets.' '' [1083] Finally, the D.C. Circuit viewed favorably the Commission's provision of a safeguard in the event that its predictions are wrong:

> FERC notes that should the Commission's sanguine predictions about market conduct turn out to be incorrect, LEPA can file a new complaint for any abuses of market power that do occur. While this escape hatch might be insufficient if LEPA had shown a substantial likelihood that FERC's predictions would prove incorrect, it provides an appropriate safeguard against the uncertainties of FERC's prognostications where there has been no such showing.[1084]

952. In the market-based rate program adopted in this rule and through other Commission actions, unlike the situation in *Texaco,* the Commission is not relying solely on the market, without adequate regulatory oversight, to set rates. Rather, it has adopted filing requirements (EQRs and change in status filings for all market-based rate sellers, regularly scheduled updated market power analyses for all Category 2 market-based rate sellers, [1085]), new

(1956); *Arkansas-Louisiana Gas Company* v. *Hall,* 453 U.S. 571, 578 n.7 (1981).

[1071] 417 U.S. at 387.

[1072] 320 U.S. at 602 (''Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.'').

[1073] *Id.* at 388.

[1074] *Id.* at 389, citing *Permian,* 390 U.S. at 776–777.

[1075] *Id.*

[1076] *Id.*

[1077] 10 F.3d at 869.

[1078] *Id.*

[1079] *Id.* at 870.

[1080] *Id.*

[1081] *Id.* at 871.

[1082] 141 F.3d at 370.

[1083] *Id.* (quoting Commission order).

[1084] *Id.* at 370–71 (footnotes and citations omitted).

[1085] In this Final Rule, the Commission creates two categories of sellers. Category 1 sellers (wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other

market manipulation rules, and a significantly enhanced market oversight and enforcement division to help oversee potential market manipulation. In addition, for sellers in RTO/ISO organized markets, Commission-approved tariffs contain specific market rules designed to prevent or mitigate exercises of market power.

953. In *Lockyer,* the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements and found that the Commission did not rely on market forces alone in approving market-based rate tariffs. The Ninth Circuit held that this dual requirement was ''the crucial difference'' between the Commission's regulatory scheme and the FCC's regulatory scheme, remanded in *MCI,* which had relied on market forces alone in approving market-based rate tariffs.[1086] The Ninth Circuit thus held that ''California's facial challenge to market-based tariffs fails'' and ''agree[d] with FERC that both the Congressionally enacted statutory scheme, and the pertinent case law, indicate that market-based tariffs do not per se violate the FPA.'' [1087] The Ninth Circuit determined that initial grant of market-based rate authority, together with ongoing oversight and timely reconsideration of market-based rate authorization under section 206 of the FPA, enables the Commission to meet its statutory duty to ensure that all rates are just and reasonable.[1088] While the court in *Lockyer* found that the Commission's market-based rate reporting requirements were not followed in that particular case, it did not find those reporting requirements invalid and, in fact, upheld the Commission's market program as complying with the FPA. The market-based rate requirements and oversight adopted in this rule are more rigorous than those reviewed by the *Lockyer* court.

954. Accordingly, the Commission rejects the position of commenters arguing that the Commission lacks authority to continue to permit market-based rates for wholesale sales of electricity. The courts have sustained the Commission's finding that market-based rates are one method of setting just and reasonable rates under the FPA. As supplemented by this Final Rule, the Commission finds that the market-based rate program complies with the statutory and judicial standards for acceptable market-based rates. We will retain our policy of granting market-based rate authority to sellers without market power under the terms and conditions set forth in this Final Rule and the Commission's regulations.

955. Further, we will retain our approach to determining whether a seller should receive authorization to charge market-based rates, as modified by the Final Rule, by analyzing seller-specific market power. The Commission has a long-established approach when a seller applies for market-based rate authority of focusing on whether the seller lacks market power.[1089] This approach, combined with our filing requirements (EQRs, change of status filings, and regularly scheduled updated market power analyses for Category 2 sellers) and ongoing monitoring through our enforcement office and complaints filed pursuant to FPA section 206, allows us to ensure that market-based rates remain just and reasonable. Moreover, for sellers in RTO/ISO organized markets, the Commission has in place market rules to help mitigate the exercise of market power, price caps where appropriate, and RTO/ISO market monitors to help oversee market behavior and conditions. As explained in our earlier discussion, we believe that the market-based rate program fully complies with judicial precedent.

Consistency of Market-Based Rate Program With FPA Filing Requirements

Comments

956. State AGs and Advocates contend that the Commission's market-based rate program fails to comply with the FPA in several ways: (1) It ignores the FPA mandate that all rates and contracts, as well as all changes in rates and contracts, must be filed in advance and made open to the public for prior review, and instead allows a seller to simply report rates after-the-fact or, in some cases, not at all; (2) it eliminates the statutory mandate that all rate increases must be noticed by filing 60 days in advance so that they can be reviewed and, if warranted, suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing; (3) it provides no objective or independent standard for determining whether ''competitive'' market-based rates are in fact ''just and reasonable;''[1090] (4) it provides no standard for determining whether market rates are unduly preferential or discriminatory; and (5) it provides no way for consumers in most cases to know what the ''just and reasonable'' rate will be in advance.[1091] They also contend that the legal presumptions that follow from the Commission's market power screens would unduly shift the burden of demonstrating the existence of market power to intervenors and away from the Commission. They argue that, until an appropriate methodology for predicting and checking market power is in place, the Commission must suspend its market-based rate regime and return to cost-of-service rates for all wholesale sales of electric power.

957. NASUCA objects that the proposed rules would prohibit utilities from filing new wholesale energy contracts,[1092] an apparent reference to the Commission's policy, since the issuance of Order No. 2001,[1093] that long-term affiliate sales contracts under a seller's market-based rate tariff are not to be filed.[1094] According to NASUCA, by not requiring sellers to file long-term market-based rate sales contracts, the Commission effectively precludes the

vertical market power issues) would not be required to file a regularly scheduled updated market power analysis, but would be subject to the change in status requirement. Category 2 sellers consist of all sellers that do not qualify as Category 1 sellers.

[1086] *Id.* at 1013.

[1087] *Id.* at 1013 & n.5; *id.* at 1014 (''The structure of the tariff complied with the FPA, so long as it was coupled with enforceable post-approval reporting that would enable FERC to determine whether the rates were 'just and reasonable' and whether market forces were truly determining the price.'').

[1088] *See Snohomish,* 471 F.3d at 1080 (in which the Ninth Circuit discusses its decision in *Lockyer*). In *Snohomish,* the Ninth Circuit explained, ''As in *Lockyer,* we do not dispute that FERC may adopt a regulatory regime that differs from the historical cost-based regime of the energy market, or that market-based rate authorization may be a tenable choice if sufficient safeguards are taken to provide for sufficient oversight.'' *Id.* at 1086.

[1089] *See, e.g., Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223, at 62,060–61 (1994); *Louisville Gas and Electric Co.,* 62 FERC ¶ 61,016, at 61,143 n.16 (1993) (and the cases cited therein); *Citizens Power & Light Corp.,* 48 FERC ¶ 61,210, at 61,776 & n.11 (1989); *Pacific Gas and Electric Co.* (Turlock), 42 FERC ¶ 61,406, at 62,194–98, *order on reh'g,* 43 FERC ¶ 61,403 (1988); *Pacific Gas and Electric Co. (Modesto),* 44 FERC ¶ 61,010, at 61,048–49, *order on reh'g,* 45 FERC ¶ 61,061 (1988). *See* also, *e.g., LEPA,* 141 F.3d at 365; *Consumers Energy Co.,* 367 F.3d 915 at 922–23 (D.C. Cir. 2004) (upholding Commission orders granting market-based rate authority, noting that the Commission's longstanding approach is to assess whether applicants for market-based rate authority do not have, or have adequately mitigated, market power).

[1090] State AGs and Advocates express doubt that the rate of return for power sold from a highly depreciated coal plant in an auction process at a market price equal to the marginal cost of a new, gas-fired plant could be within a zone of reasonableness. State AGs and Advocates at 25–26.

[1091] *Id.* at 19–20.

[1092] NASUCA at 32–33.

[1093] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs., Regs. Preambles 2001–2005 ¶ 31,127 (2002). *See* 18 CFR 35.10b.

[1094] NASUCA at 27–29.

public and others from objecting before the rates take effect. Additionally, NASUCA states that there is no statutory basis for a Commission rule directing sellers not to file their rates when the statute says exactly the opposite.[1095] AARP similarly comments that the Commission's policy of monitoring long-term market-based sales through quarterly reports is too little oversight too late to ensure that such rates are just and reasonable. AARP argues that the Commission should reconsider its policy on affiliate transactions and asserts that all affiliate contracts should be filed and reviewed under section 205 to comply with the express requirements under the FPA.[1096]

958. NASUCA also argues that the proposed rule allows sellers with cost-based rates to declare their own rates without filing them, subject to Commission review when the sales are for less than one year. It contends that the burden of proof, under *Farmers Union Central Exchange, Inc.* v. *FERC*[1097] and *Texaco*,[1098] is on the Commission to demonstrate empirical proof that consumers are provided the ''complete, effective and permanent bond of protection from excessive rates'' that the statute anticipates.[1099]

Commission Determination

959. We reject State AGs and Advocates' arguments that the Commission's market-based rate program fails to comply with the FPA. Contrary to State AGs and Advocates' contention that the Commission's market-based rate program ''ignores the FPA mandate that all rates and contracts, as well as all changes in rates and contracts, must be filed in advance and made open to the public for prior review'' and instead ''allows sellers to simply 'report' rates after-the-fact, or in some cases, not at all,''[1100] as the courts have found, the Commission's market-based rate program does not violate the FPA's filing requirements. The FPA requires that every public utility file with the Commission ''schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission,''[1101] but it explicitly leaves the timing and form of those filings to the Commission's discretion. Public utilities must file ''schedules showing all rates and charges'' under ''such rules and regulations as the Commission may prescribe,'' and ''within such time and in such form as the Commission may designate.''[1102]

960. We note that the courts have recognized the Commission's discretion in establishing its procedures to carry out its statutory functions. For example, the Ninth Circuit, in denying a California Commission request to order the Commission to adopt different market-based rate tariff reporting requirements, observed:

> Congress specified that filings be made ''within such time and with such form'' and under ''such rules and regulations as the Commission may prescribe.'' 16 U.S.C. § 824d(c). Thus, so long as FERC has approved a tariff within the scope of its FPA authority, it has broad discretion to establish effective reporting requirements for administration of the tariff.[1103]

961. The market-based rate tariff, with its appurtenant conditions and requirement for filing transaction-specific data in EQRs, is the filed rate. As the Commission has held, if every service agreement under a previously-granted market-based rate authorization had to be filed for prior approval, then the original market-based rate authorization would be a pointless exercise.[1104]

962. We also disagree with State AGs and Advocates' argument that the market-based rate program eliminates the statutory mandate that all rate increases be noticed by filing 60 days in advance and, if warranted, suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing. The Commission has developed a thorough process to evaluate the sellers that it authorizes to enter into transactions at market-based rates. Under the market-based rate program, the rate change is initiated when a seller applies for authorization of market-based rate pricing. All applications are publicly noticed, entitling parties to challenge a seller's claims. At that time, there is an opportunity for a hearing, with the burden of proof on the seller to show that it lacks, or has adequately mitigated, market power, and for the imposition of a refund obligation. In addition, if a seller is granted market-based rate authority, it must comply with post-approval reporting requirements, including the quarterly filing of transaction-specific data in EQRs,[1105] change of status filings for all sellers, and regularly-scheduled updated market power analyses for Category 2 sellers.

963. In addition, we disagree with State AGs and Advocates' arguments that the Commission failed to show how competitive market-based rates are just and reasonable and not unduly discriminatory or preferential. The standard for judging undue discrimination or preference remains what it has always been: Disparate rates or service for similarly situated customers.[1106] As the Commission has held in prior cases, and as the courts have upheld, rates that are established in a competitive market can be just, reasonable and not unduly discriminatory.[1107] Rates do not have to be set by reference to an accounting cost of service to be just, reasonable and not unduly discriminatory. When the Commission determines that a seller lacks market power, it is therefore making a determination that the resulting rates will be established through competition, not the exercise of market power. Furthermore, the Commission's market-based rate program includes many ongoing regulatory protections designed to ensure that rates are just and reasonable and not unduly discriminatory or preferential. The filing and reporting requirements incorporated into the market-based rate program (EQRs, change in status filings, regularly-scheduled updated market power analyses) help the Commission to prevent, to discover and to remedy exercises of market power and unduly discriminatory rates. In addition, the adoption of *pro forma* transmission tariff provisions that apply industry-

[1095] *Id.* at 28.

[1096] AARP at 12.

[1097] 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. *Williams Pipe Line Company* v. *Farmers Union Central Exchange, Inc.,* 469 U.S. 1034 (1984) (Farmers Union).

[1098] 417 U.S. 380 (1974).

[1099] NASUCA cites *Atlantic Ref. Co.* v. *Pub. Serv. Comm'n of State of N.Y.,* 360 U.S. 378, 388 (1959).

[1100] State AGs and Advocates at 19.

[1101] 16 U.S.C. 824d(c).

[1102] *Id.*

[1103] *Lockyer,* 383 F.3d at 1013. *See also Wabash Valley Power Association* v. *FERC,* 268 F.3d 1105, 1115 (citing with approval the Commission's authority to fix just and reasonable rates under section 206 as a condition of its market-based rate authorization); *Environmental Action* v. *FERC,* 996 F.2d 401, 407–08 (D.C. Cir. 1993) (in which the D.C. Circuit recognized ''the Commission's determination to streamline its regulatory process to keep pace with advances in information technology. Ratemaking is a time-consuming process.'').

[1104] *GWF Energy LLC,* 98 FERC ¶ 61,330, at 62,390 (2002).

[1105] The Ninth Circuit found the pre-EQR quarterly reporting requirements to be ''integral to the [market-based rate] tariff'' and that they, together with the Commission's initial approval of market-based rate authority, comply with the FPA's requirements. *Lockyer,* 383 F.3d at 1016. As discussed elsewhere in this Final Rule, through the EQRs, the Commission has enhanced and updated the post-transaction quarterly reporting filing requirements that were in place during the period at issue in *Lockyer.*

[1106] *See, e.g., Southwestern Electric Cooperative, Inc.* v. *FERC,* 347 F.3d 975, 981 (D.C. Cir. 2003).

[1107] *See, e.g., Lockyer,* 383 F.3d at 1012–13; *Tejas Power Corp.* v. *FERC,* 980 F.2d 998, 1004 (D.C. Cir. 1990).

wide ensures that potential customers are treated similarly in obtaining transmission access to energy providers. Moreover, Commission-approved RTOs and ISOs run real-time energy markets under Commission-approved tariffs.[1108] These single price auction markets set clearing prices on economic dispatch principles, to which various safeguards have been added to protect against anomalous bidding.

964. Thus, the Commission, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates should those steps be necessary. For example, based on its review of updated market power updates, its review of EQR filings made by market-based rate sellers, and its review of required notices of change in status, the Commission may institute a section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission may also, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty paid to the United States Treasury if a seller is found to have engaged in prohibited market manipulation or to have violated Commission orders, tariffs or rules.

965. In the NOPR that preceded Order No. 2001, the Commission noted that it needed to make changes to keep abreast of developments in the industry, *e.g.*, it had approved umbrella tariffs for market-based rates by public utilities and there had been a significant increase in the number of section 205 filings after the Commission's open access initiatives in Order Nos. 888 and 889.[1109] The Commission explained:

> Under the Commission's current filing requirements in 18 C.F.R. Part 35, individual service agreement filings associated with approved tariffs require a significant amount of time, effort, and expense on the part of public utilities to prepare and serve on their customers and the Commission. These individual filings also require a significant amount of staff time and effort associated with docketing, noticing, loading the information onto RIMS, and other processing tasks. Further, the information contained in such filings that is most relevant to customers and the Commission could also be provided in an alternative, streamlined form, thus continuing to satisfy the requirements of FPA section 205(c), but in a more efficient manner. Accordingly, we propose to replace the filing of individual service agreements and Quarterly Transaction Reports with the filing of an electronic Index of Customers. This format will greatly increase the accessibility and usefulness of the relevant data, which will confer greater benefits to the public.[1110]

966. The Commission implemented the revised filing requirements in Order No. 2001. In so doing, it further explained that:

> The revised filing public utility requirements adopted in this Final Rule create a level playing field vis-à-vis the filing requirements applicable to traditional utilities and power marketers. While the data to be reported in the data sets reduces public utilities' overall reporting burden as compared to existing requirements, it is hoped that the Electric Quarterly Reports' more accessible format will make the information more useful to the public and the Commission will better fulfill the public utilities' responsibility under FPA section 205(c) to have rates on file in a convenient form and place. The data should provide greater price transparency, promote competition, enhance confidence in the fairness of markets, and provide a better means to detect and discourage discriminatory practices.[1111]

967. Thus, we find that the multiple layers of filing and reporting requirements incorporated into the market-based rate program meet the filing requirements of the FPA and, in conjunction with our enhanced market oversight and enforcement functions within the Commission, as well as the ability of the public to file section 206 complaints, provide adequate protection from excessive rates. Given our broad discretion to determine the procedures to carry out our statutory duties, our market-based rate program fully complies with the requirements of the FPA.[1112]

968. Although State AGs and Advocates also argue that the legal presumptions that follow from the Commission's market power screens would unduly shift the burden of demonstrating the existence of market power to intervenors, the Commission previously addressed and rejected this argument. On rehearing of the April 14 Order, the Commission explained that nothing in that order shifts the burden of proof that section 205 imposes on the filing utility. Passing both screens or failing one merely establishes a rebuttable presumption. To challenge a seller who passes both screens, the intervenor need not conclusively prove that the seller possesses market power. Rather, the intervenor need only meet a burden of going forward with evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the seller to prove that it lacks market power.[1113] Ultimately, the burden of proof under section 205 belongs to the seller.

969. With respect to NASUCA's and AARP's concern about long-term affiliate sales contracts not being filed, we note that since 2002, the Commission's regulations have provided that long-term market-based rate power sales service agreements, with affiliates or otherwise, are not to be filed with the Commission.[1114] Although commenters acknowledge that the Commission first considers in a separate proceeding whether to authorize affiliate transactions, they believe that the Commission should nevertheless review the resulting rates in a proceeding under FPA section 205 before they go into effect.

970. NASUCA and AARP have not convinced us that this practice needs to be modified as a legal or policy matter. Our market-based rate program incorporates numerous protections against excessive rates, regardless of the identities of the parties to a transaction, and commenters do not provide any compelling reason why affiliate transactions should be treated any differently. To the extent that a

[1108] In response to State AGs and Advocates' argument about the rate of return for a seller receiving a market clearing price for power sold in an auction process, the issue does not concern whether a particular seller should have market-based rate authority, and it is more appropriately addressed in the context of an RTO/ISO proceeding rather than in this rulemaking proceeding.

[1109] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 61 FR 21737 (1996), FERC Stats. & Regs., Regs. Preambles ¶ 31,037 (1996), *order on reh'g*, Order No. 889–A, 62 FR 12484 (1997), FERC Stats. & Regs., Regs. Preambles ¶ 31,049 (1997), *reh'g denied*, Order No. 889–B, 81 FERC ¶ 61,253 (1997), *aff'd in part and rev'd in part sub nom Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC*, 535 U.S. 1 (2002).

[1110] *Revised Public Utility Filing Requirements, Notice of Proposed Rulemaking*, FERC Stats. & Regs., Proposed Regulations 1999–2003, ¶ 32,554 at 34,062 (2001).

[1111] Order No. 2001, FERC Stats. & Regs., Regs. Preambles 2001–2005 ¶ 31,127 at P 31.

[1112] Moreover, the decision to eliminate the filing of market-based rate contracts was made almost five years ago in a generic rulemaking proceeding that was open to participation by all interested parties. Commenters' failure to raise this concern in that proceeding precludes them from attacking the Commission's well-settled practice here.

[1113] July 8 Order, 108 FERC ¶ 61,026 at P 29.

[1114] *See* 18 CFR 35.1(g) (''[A]ny market-based rate agreement pursuant to a tariff shall not be filed with the Commission'').

particular affiliate relationship presents issues of concern, they will be considered in the context of our determination whether to authorize any affiliate sales. Accordingly, we will continue to direct sellers not to file long-term market-based rate sales contracts, unless otherwise permitted by Commission rule or order.

971. Regarding NASUCA's assertion that our proposals would allow sellers with cost-based rates to declare their own rates without filing them, we emphasize that all mitigation proposals, whether based on the default cost-based rates or some other cost-based rates, must be filed with the Commission for review. As we make clear above in the Mitigation section of this Final Rule, any such filings are noticed, and interested parties are given an opportunity to intervene, comment on, or protest the submittal.

2. Whether Existing Tariffs Must Be Found To Be Unjust and Unreasonable, and Whether the Commission Must Establish a Refund Effective Date

Comments

972. NASUCA states that the Commission invokes sections 205 and 206 of the FPA as authority for the proposed action, including modifying all existing market-based rate authorizations and tariffs so they will be expressly conditioned on or revised to reflect certain new requirements. NASUCA submits that any action taken under section 206 must be prefaced by a Commission finding that existing rates are unjust and unreasonable and the fixing of a refund effective date. It argues that the Commission has failed to make express findings necessary to support its proposal to modify all existing market-based rate tariffs under section 206 or to explain how it can modify the existing tariffs without finding that they are not just and reasonable and establishing a refund effective date.[1115]

Commission Determination

973. As discussed above in the MBR Tariff section, in requiring all sellers to revise their existing market-based rate tariffs to include certain standard provisions, the Final Rule finds that continuing to allow basic inconsistencies in the market-based rate tariffs on file with the Commission is unjust and unreasonable. Thus, NASUCA's concern in that regard is addressed.

974. We disagree with NASUCA that we must establish a refund effective date because we are establishing rules under section 206. Even if section 206 were read to require the establishment of a refund effective date in rulemakings initiated under section 206, rather than only in case-specific section 206 investigations initiated by complaints or *sua sponte* by the Commission,[1116] we have broad discretion to adopt generic policy or make generic findings through either a rulemaking or adjudication, and we have discretion whether to order refunds.[1117] This proceeding is not an adjudicatory investigation of public utilities' existing market-based rate tariffs for which refunds will be required. Rather, we are modifying existing market-based rate tariffs prospectively only through this rulemaking.[1118] Accordingly, the establishment of a refund effective date in this rulemaking would be meaningless.

H. Miscellaneous

1. Waivers

Commission Proposal

975. The Commission has granted certain entities with market-based rate authority, such as power marketers and independent or affiliated power producers, waiver of the Commission's Uniform System of Accounts (USofA) requirements, specifically waiver of Parts 41, 101, and 141 of the Commission's regulations.[1119] The Commission has also granted blanket approval under Part 34 of the Commission's regulations for future issuances of securities and assumptions of liability where the entity seeking market-based rate authority, such as a power marketer or power producer, is not a franchised public utility.

976. In the NOPR, the Commission noted that, as the development of competitive wholesale power markets continues, independent and affiliated power marketers and power producers are playing more significant roles in the electric power industry. In light of the evolving nature of the electric power industry, the Commission sought comment on the extent to which these entities with market-based rate authority should be required to follow the USofA; what financial information, if any, should be reported by these entities; how frequently it should be reported; and whether the Part 34 blanket authorizations continue to be appropriate.

977. The Commission noted that some sellers have had their market-based rate authority revoked, or have elected to relinquish their market-based rate authority after a presumption of market power, and have begun or resumed selling power at cost-based rates. As discussed in the April 14 Order, any waivers previously granted in connection with those sellers' market-based rate authority are no longer applicable. Thus, the Commission currently rescinds any accounting and reporting [1120] waivers for mitigated sellers in the mitigated control area. Similarly, the Commission stated in the April 14 Order that it would rescind any blanket authorizations under Part 34 for the mitigated seller and its affiliates. In the NOPR, the Commission proposed that, in the case of any affiliates, this would entail rescission of blanket authorizations in all geographic areas, not just the mitigated control area.

978. The Commission proposed in the NOPR that any repeal of previously granted waivers become effective 60 days from the date of an order repealing such waivers in order to provide the affected utility with time to make the necessary filings with the Commission and to allow for an orderly transition from selling under market-based rates to cost-based rates. The Commission sought comment on that proposal. The Commission also sought input regarding any difficulties sellers may have when transitioning to cost-based rates and whether a prior waiver of the accounting regulations would leave them without adequate data to come into conformance with the accounting rules.

[1115] NASUCA at 32.

[1116] The Congressional intent of the Regulatory Fairness Act of 1988 (RFA), which added the refund effective date provision to section 206, was to expedite the resolution of complaint proceedings. Congress believed that, pre-RFA, public utilities had little incentive to settle meritorious section 206 complaints since any relief was prospective only, and the public utilities kept any revenues collected during the pendency of a section 206 proceeding. The purpose of the legislation was to ''correct this problem by giving FERC the authority to order refunds, subject to certain limitations.'' S. Rep. No. 491, 100th Cong., 2d Sess. 3 (1988), *reprinted in* 1988 U.S.C.C.A.N. 2684, 2685. In so doing, Congress left it to the Commission's discretion to determine when the public interest would be served by requiring refunds under section 206, stating ''Because the potential range of these situations cannot be fully anticipated, no attempt has been made to enumerate them here.'' S. Rep. No. 491, 100th Cong., 2d Sess. 6, *reprinted in* 1988 U.S.C.C.A.N. 2688. Nowhere in the Senate Report does Congress mention setting refund effective dates in rulemakings.

[1117] *See, e.g., Lockyer*, 383 F.3d at 1016.

[1118] *E.g., Wisconsin Gas Co.* v. *FERC*, 770 F.2d 1144, 1166 (D.C. Cir. 1985); *SEC* v. *Chenery*, 332 U.S. 194, 202–03, *reh'g denied*, 332 U.S. 747 (1947).

[1119] Part 41 pertains to adjustments of accounts and reports; Part 101 contains the Uniform System of Accounts for public utilities and licensees; Part 141 describes required forms and reports.

[1120] *See* 18 CFR 41.10–41.12, 141.1, 141.2 and 141.400.

a. Accounting Waivers

Comments

979. The majority of commenters who comment on this topic urge the Commission to retain existing waivers of the accounting regulations.[1121] They submit that the Commission's accounting requirements are only relevant when the utility or marketer that is being regulated charges cost-based rates. EPSA states that where a market-based rate seller neither has cost-of-service rates nor captive customers from which to recover cost-of-service rates, requiring such entities to comply with the USofA would be burdensomely expensive and would serve no purpose. The commenters explain that there has been no change in the industry that warrants a departure from the Commission's precedent. Commenters state that a change in policy would serve no public benefit, and the costs that such market-based rate sellers would have to incur in order to collect and report such data would substantially outweigh the benefit of collecting and reporting it.

980. Financial Companies state that there is no reason for the Commission to run the risk of discouraging participation in the energy markets and chilling investment by requiring power marketers and power producers who currently lack market power to comply with the USofA absent concrete evidence that the wholesale power markets are being harmed by the Commission's current practice of granting waivers or blanket authority.[1122]

981. Absent special circumstances, Sempra supports the current waivers and explains that the electric quarterly transaction reports submitted pursuant to Order No. 2001 [1123] provide detailed information regarding transactions entered into by entities authorized to make market-based rate sales. Sempra also notes that the retention of these waivers for market-based rate entities is also consistent with the treatment of power marketers and exempt wholesale generators (EWGs) under the Public Utility Holding Company Act of 2005 and the Commission's regulations promulgated thereunder.[1124]

982. APPA/TAPS suggest that the Commission provide waivers to Category 1 sellers, but not for Category 2 sellers.[1125] In response to the Commission's question about the orderly transition from market-based to cost-based rates and the role that waivers may play in making that transition more difficult, APPA/TAPS suggest that Category 2 sellers are more likely than Category 1 sellers to lose market-based rate authority and find themselves subject to cost-based rates; accordingly, not providing the waivers for Category 2 sellers should address these transition concerns.

Commission Determination

983. We will continue the Commission's historical practice of granting waiver of Parts 41, 101, and 141 of the Commission's regulations to certain entities with market-based rate authority. We agree with EPSA that little purpose would be served to require compliance with accounting regulations for entities that do not sell at cost-based rates and do not have captive customers. Such entities typically include power marketers and independent and affiliated power producers that are not franchised public utilities.[1126]

984. We conclude that the costs of complying with the Commission's USofA requirements and, specifically Parts 41, 101, and 141 of the Commission's regulations, outweigh any incremental benefits of such compliance where the seller only transacts at market-based rates.[1127] Further, the risk of discouraging participation in the energy markets and the potential chilling effect on investment caused by requiring power marketers and power producers, who do not otherwise have a cost-based rate on file with the Commission, to comply with the USofA outweigh the added oversight the Commission might gain in this regard.

985. As we have done in the past, previously granted waivers of the accounting requirements will continue to be rescinded where a seller is found to have market power (or where the seller accepts a presumption of market power) and the seller proposes cost-based rate mitigation or the Commission imposes cost-based rate mitigation. Although the Commission stated in the NOPR that it would also revoke the accounting waivers for any of the mitigated seller's affiliates with market-based rates in the mitigated balancing authority area, we clarify that we will not require revocation of the accounting and reporting waivers for a power marketer affiliated with a mitigated seller where such power marketer has no assets, no cost-based rate on file, and its applicable tariff prohibits sales in the mitigated balancing authority area.[1128]

986. With regard to APPA/TAPS's suggestion that the Commission provide waivers to sellers that qualify for Category 1 and not to sellers that qualify for Category 2, we decline to adopt such an approach. While APPA/TAPS may be correct that Category 2 sellers are more likely than Category 1 sellers to possess market power, we do not grant such accounting waivers based on the size of the seller (which is, to a great extent, the critical factor in determining in which category the seller is placed). Rather, as discussed above, the waivers are granted on the basis of whether the seller is a franchised public utility or otherwise is selling at cost-based rates.

987. Finally, we note that all sellers, irrespective of accounting or other waivers, must file EQRs regarding their transactions. In addition, we agree with APPA/TAPS that any waivers in this rule do not exempt a holding company or service company from applicable reporting requirements under the Commission's PUHCA 2005 regulations.

b. Timing

Comments

988. Regarding the proposal that rescission of accounting and reporting waivers become effective 60 days from the date of an order rescinding such waivers, several commenters state that 60 days may not be enough time for sellers who have their market-based rate authority revoked, or have elected to relinquish their market-based rate

[1121] *See, e.g.*, Ameren at 23–24; EPSA at 33–36; Constellation at 23–27; EEI at 49–52; Morgan Stanley at 9–10; Ormet at 15–17; PPM at 6–7.

[1122] Financial Companies at 18.

[1123] *Revised Public Utility Filing Requirements*, Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002); *reh'g denied*, Order 2001–A, 100 FERC ¶ 61,074 (2002); *reconsideration and clarification denied*, Order No. 2001–B, 100 FERC ¶ 61,342 (2002); *further order*, Order No. 2001–C, 101 FERC ¶ 61,314 (2002).

[1124] Sempra at 8–9, *citing* Public Utility Holding Company Act of 2005, Pub. L. No. 109–58 1261 *et seq.*, 119 Stat. 594 (2005) (PUHCA 2005).

[1125] However, any such waivers should not exempt a holding company or service company from applicable reporting requirements under the Commission's PUHCA 2005 regulations. APPA/TAPS at 29–30.

[1126] Likewise, we will continue to grant waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for 18 CFR 35.12(a), 35.13(b), 35.15 and 35.16. We note that this waiver would not be granted to an entity that makes sales at cost-based rates.

[1127] We have previously stated that Parts 41, 101 and 141 prescribe certain accounting and reporting requirements that focus on the assets that a utility owns, and waiver of these requirements is appropriate where the utility ''will not own any such assets, its jurisdictional facilities will be only corporate and documentary, its costs will be determined by utilities that sell power to it, and its earnings will not be defined and regulated in terms of an authorized return on invested capital.'' *Citizens Power & Light Corp.*, 48 FERC ¶ 61,210 at 61,780 (1989).

[1128] *See, e.g., APS Energy Services Company, Inc.*, 117 FERC ¶ 61,158 (2006).

authority after a presumption of market power and have begun or resumed selling power at cost-based rates, to conform to the Commission's accounting requirements.[1129]

989. EEI supports providing such companies at least six months post revocation to comply with USofA recordkeeping requirements.[1130] EEI states that the Commission should allow the companies to begin keeping records under the USofA starting at the beginning of the next calendar year, or the companies' fiscal year, if different, and to report the information the following year.[1131] argues that to put USofA in place and begin complying with the Commission's reporting requirements such as the annual FERC Form 1 and quarterly FERC Form No. 3–Q takes substantial company time and resources. EEI explains that companies must put the necessary accounts and reporting formats in place within their accounting systems. This involves substantial training of staff, modification of accounting software, testing to ensure proper internal controls under the Sarbanes Oxley Act of 2002,[1132] and review by company management and internal and external auditors to ensure accuracy under the securities laws and the Sarbanes Oxley Act. EEI submits that these measures can be quite costly—in the millions of dollars for larger companies—and they take time to implement.

990. Constellation supports the 60-day transition period as reasonable but seeks clarification that under this approach the entity would be required to (1) Maintain its accounts in accordance with the Commission's USofA only for periods beginning at the end of such transition period, and (2) obtain specific authorization for securities to be issued, or liabilities to be assumed, subsequent to the end of such transition period.[1133]

Commission Determination

991. We adopt the NOPR proposal that rescission of waivers of Parts 41, 101 and 141 of the Commission's regulations granted in connection with a seller's market-based rate authority will become effective 60 days from the date of an order revoking such waivers. We believe that this strikes a reasonable balance between the need to have adequate financial information on file with the Commission and the desire to provide sellers adequate time to comply.

992. In our consideration of the transition period for complying with the accounting and reporting requirements, the Commission finds that commenters have not sufficiently supported their request for a transition period of six months or more. EEI's arguments with respect to the time and money required to train staff and modify and test accounting software do not outweigh the need for the Commission to obtain financial information with regard to mitigated sellers so that we can meet our obligation under the FPA to ensure that rates remain just and reasonable and not unduly discriminatory or preferential. We note that our experience has shown that a 60-day transition period is sufficient time for a mitigated seller to comply with the accounting requirements.[1134]

993. In response to Constellation's request for clarification, we clarify that a seller losing or relinquishing its market-based rate authority will be required to maintain its accounts in accordance with the Commission's USofA [1135] and will be subject to quarterly and annual reporting requirements (FERC Form Nos. 3–Q, 1, or 1–F) [1136] as of the effective date of the rescission of such waivers, *i.e.*, 60 days from the date of the order rescinding the waivers. In this regard, such sellers will be required to comply with our accounting regulations (Part 101) beginning with the effective date of the rescission of such waiver. For quarterly reporting in FERC Form No. 3–Q, the seller will be required to submit FERC Form No. 3–Q beginning with the quarter in which the rescission of the accounting and reporting waivers becomes effective.[1137] The seller will also be required to submit a FERC Form No. 1 or 1–F, as applicable, beginning in the year in which the rescission of the accounting and reporting waivers becomes effective.[1138] For example, if the effective date of rescission occurs on May 15, the seller must make the 3–Q filing for the second quarter (April–June) at its regularly scheduled time even though it has not previously filed a Form 1.[1139] If a particular seller is unable to meet the applicable filing dates, it may petition the Commission for an extension. We will consider such requests on a case-by-case basis.

c. Part 34 Waivers Blanket Authorizations

Comments

994. In response to the Commission's inquiry regarding whether Part 34 blanket authorizations (pertaining to issuances of securities or assumptions of liabilities) continue to be appropriate, all commenters addressing the issue urge the Commission to retain its current policy.[1140] They submit that Commission oversight of securities issuances and assumptions of liabilities is only relevant for franchised public utilities and that prior authorization under section 204 is not necessary for market-based rate sellers that do not intend to ''become a public service franchised providing electricity to consumers dependent upon [their] services.'' [1141] Financial Companies state that there is no reason for the Commission to risk adversely affecting energy markets by requiring entities that currently lack market power to secure agency approval each time they want to issue securities or assume liabilities.

995. With regard to the statement in the NOPR that the Commission will rescind blanket authorizations for the mitigated seller and its affiliates in all geographic areas, not just the mitigated control area, Duke strongly opposes rescission of blanket section 204 authorizations for all affiliates of the mitigated seller in all markets. Duke

[1129] *See* Ameren at 24; EEI at 48–49; Mirant at 15–16.

[1130] Mirant also supports providing six months to comply with the reporting requirements and states that, in addition, the Commission should grant extensions to that deadline based upon a demonstration that the entity is working in good faith to comply with the deadline but, due to factors beyond the entity's control, the deadline needs to be extended. Mirant at 15–16.

[1131] EEI at 48–49.

[1132] Sarbanes Oxley Act of 2002, Pub. L. 107–204, 116 Stat. 745.

[1133] Constellation at 33. *See also* PPL at 26–27 (supports proposal to keep waivers effective for 60 days from date of order revoking market-based rate authority).

[1134] *See Entergy Services, Inc*, 115 ¶ FERC 61,260 (2006) (revoking waivers and authorizations previously granted to certain Entergy Affiliates). Accounting systems were in place within 60-days from the effective date of the order rescinding the waivers and the company was granted an additional 30-day extension to file the upcoming quarterly report. *See Entergy Services, Inc.,* Docket No. AC06–257–000 (Nov. 21, 2006) (unpublished letter order).

[1135] 18 CFR Part 101.

[1136] *See* 18 CFR 141.1, 141.2, 141.400.

[1137] The first quarterly filing made by the seller will include information from the effective date of the rescission through the end of the calendar quarter.

[1138] The first annual filing of FERC Form No. 1 or 1–F will include information beginning with the effective date of the rescission through the end of the calendar year. Additionally, there is a requirement that goes along with these forms that requires the submission of a CPA Certification Statement (18 CFR 41.10–41.12).

[1139] In this example, the seller's 3–Q for the second quarter must reflect our accounting regulations as of May 15, the effective date of rescission of such waivers.

[1140] *See, e.g.*, Cogentrix at 3–6; PPL at 25–27; TXU at 5–7; AWEA at 4–5; Duke supplemental comments at 1–8; Powerex at 26–28.

[1141] *See* Cogentrix at 5, citing *Citizens Energy Corp.,* 35 FERC ¶ 61,336 at 61,455 (1986). Cogentrix notes that entities with such blanket authorizations do not provide the service that franchised utilities are obligated to offer to their captive customers and that FPA section 204 and 18 CFR Part 34 are intended to protect.

urges the Commission to limit such rescission only to those market-based rate sellers making sales to captive customers in areas where there is a finding of market power.[1142] Duke states that the purpose of section 204 is to ensure the financial viability of franchised public utilities. As a result, prior authorization is appropriate for independent and affiliated power marketers with market-based rate authority who do not intend to assume public service franchise obligations.

996. Duke argues that the Commission has not explained how issuance of a security or assumption of a liability by an affiliated marketer or merchant generator could be contrary to the public interest merely because an affiliate is deemed to have market power in power sales markets in a particular geographic area. Duke asserts that there is no evidence presented in the NOPR that would support the presumed linkage between a determination of a seller's market power in a particular geographic market and the ability of that seller's affiliates to leverage such market power in other geographic markets through their issuances of securities or debt. Duke says that this is especially true in the case of entities such as the Duke affiliates, which have amended their tariffs to preclude market-based rate sales in the Duke Power control area, the only geographic market where the company was determined to have market power. Given that no market-based rate sales will be made by the affiliates in the only geographic area where there was even an issue of market power, Duke states that there is no possible nexus between securities issuances by these entities and protecting the franchised customers of Duke's traditional utility affiliates.

997. Duke concludes that the Commission should determine that blanket authorizations under section 204 for market-based rate sellers should not be affected by a finding that a utility affiliate can exercise market power in its control area or other geographic markets. In the alternative, Duke asks the Commission to determine that, in cases where sellers cannot sell power at market-based rates in the geographic market(s) where an affiliated traditional utility is found to have market power, there can be no anti-competitive effects or need to protect franchise customers, and thus affiliated sellers should be able to obtain (or retain) blanket section 204 authorizations.

Commission Determination

998. We will continue to grant blanket approval under Part 34 for future issuances of securities and assumptions of liability where the entity seeking market-based rate authority, such as a power marketer or power producer, is not a franchised public utility or does not otherwise provide requirements service at cost-based rates.[1143] The Commission traditionally has granted blanket authorization for the issuance of securities and assumptions of liability to power sellers not subject to cost-based rate regulation, *i.e.*, power sellers that have market-based rate authority.[1144] As the Commission has explained in previous cases involving market-based rate authority in which the sellers sought blanket authorization of issuances of securities or assumptions of liability, the purpose of section 204 of the FPA, which Part 34 implements, is to ensure the financial viability of public utilities obligated to serve consumers of electricity.[1145] Accordingly, where the seller is not a franchised public utility providing electric service to customers under cost-based regulation and has market-based rate authority, the Commission's practice is to grant the blanket authorization, subject to consideration of objections by an interested party.

999. We do not adopt the NOPR proposal concerning the rescission of blanket authorizations for affiliates of mitigated sellers. After careful consideration of the comments received, we will limit such rescission to the mitigated seller and its affiliates making sales within the mitigated balancing authority area. Our decision here takes into account Duke's and PPL's arguments against rescission of blanket authorization for all affiliates in all markets. We conclude that it is not necessary to rescind such blanket authorizations in the case of affiliates that make sales outside of the mitigated balancing authority area because the seller retains its market-based rate authority in unmitigated markets. We clarify that the effective date for rescinding blanket authorization under Part 34 will be commensurate with the date on which a mitigated seller begins to sell power at cost-based rates. Further, sellers losing their market-based rate authority must file with the Commission to obtain specific authorization for securities to be issued, or liabilities to be assumed, prior to the date the seller first sells at cost-based rates.

2. Sellers Affiliated With a Foreign Utility

Commission Proposal

1000. Under existing policy, a seller affiliated with a foreign utility selling in the United States (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing. However, for sellers affiliated with a foreign utility, the Commission has allowed a modified approach to the current four prongs.

1001. With regard to generation market power, should any of the seller's first-tier markets include a United States market, the seller performs the market power screens in that control area(s). With regard to transmission market power, the Commission requires the seller affiliated with a foreign utility seeking market-based rate authority to demonstrate that its transmission-owning affiliate offers non-discriminatory access to its transmission system that can be used by its competitors to reach United States markets. The Commission does not consider transmission and generation facilities that are located exclusively outside of the United States and that are not directly interconnected to the United States. However, the Commission would consider transmission facilities that are exclusively outside the United States but nevertheless interconnected to an affiliate's transmission system that is directly interconnected to the United States. A seller affiliated with a foreign utility must inform the Commission of any potential barriers to entry that can be exercised by either it or its affiliates in the same manner as a seller located within the United States. Regarding affiliate abuse, the requirement that a power marketer with market-based rate authority file for approval under section 205 of the FPA before selling power to a utility affiliate does not apply to situations involving sales of power to a

[1142] Duke supplemental comments at 1–8. *See also* PPL at 26 (loss of any waiver should apply only to the seller or affiliates that make wholesale sales in the control area where market-based rate authority is lost, but not to affiliates that do not conduct business in that control area).

[1143] *See, e.g., Golden Spread Electric Coop., Inc.,* 97 FERC ¶ 61,025 at 61,070 (2001) (''While Golden Spread has been granted market-based rate authority, it also makes requirements sales under Commission-accepted, cost-based rates. Since Golden Spread sells power at cost-based rates and not solely at market-based rates, it fails to qualify for blanket approval to issue securities.'').

[1144] *Merrill Lynch Commodities, Inc.,* 108 FERC ¶ 61,233 at P 16 (2004).

[1145] *Id.* (*citing Citizens Energy Corp.,* 35 FERC ¶ 61,198 at p. 61,455 (1986); *Howell Gas Management Co.,* 40 FERC ¶ 61,336 at p. 62,026 (1987)).

foreign utility outside of the Commission's jurisdiction.

1002. The Commission proposed in the NOPR to retain its current policy when reviewing the application for market-based rate authorization by a seller affiliated with a foreign utility, and sought comment regarding whether the current policy is adequate to grant market-based rate authorization to such sellers. No comments were submitted on the broad question of whether our current policy, in general, is adequate. However, Powerex and NL Hydro [1146] raise specific issues that are addressed below. As discussed below, we conclude that our current approach needs no modification. Accordingly, we will adopt the NOPR proposal to retain our current policy when reviewing an application for market-based rate authority by a seller affiliated with a foreign utility.

Comments

1003. Powerex notes that comparability for non-jurisdictional United States-based transmission providers (''unregulated transmitting utilities'' under the FPA) is now defined by statute to mean service ''at rates that are comparable to those that the unregulated transmitting utility charges itself'' and ''on terms and conditions that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' [1147] Powerex notes that, in the OATT Reform NOPR, the Commission proposed to apply the comparability requirement of FPA section 211A on a case-by-case basis, *i.e.*, by complaint.[1148] Powerex states that, under principles of national treatment as set out in the North American Free Trade Agreement (NAFTA), the Commission should impose no more stringent a burden on similarly non-jurisdictional Canadian and Mexican transmission-owning utilities. For that reason, Powerex urges the Commission to clarify that it will presume that Canadian and Mexican transmitting utilities are providing comparable and not unduly discriminatory or preferential transmission service unless this presumption is otherwise rebutted by third party or Commission-instituted complaint.[1149]

1004. NL Hydro urges the Commission to reject Powerex's suggestion that the Commission no longer should require market-based rate sellers to affirmatively demonstrate that non-discriminatory access is offered on transmission facilities that they or their affiliates own, control, or operate outside of the United States. NL Hydro argues that the comparability standard of FPA section 211A does not govern the Commission's market-based rate analysis of transmission market power.[1150] It states that the Commission has not suggested, in either this proceeding or the OATT rulemaking, that the comparability standard in FPA section 211A should create a presumption that any market-based rate seller (domestic or affiliated with a foreign utility) should be presumed to have passed the transmission market power test.[1151]

1005. NL Hydro supports the Commission's proposal to retain its existing requirements with respect to the mitigation of transmission market power when reviewing the market-based rate applications of sellers affiliated with a foreign utility. According to NL Hydro, these requirements establish a reasonable balance among important regulatory objectives by: (1) Requiring non-discriminatory access to foreign transmission facilities for access to United States markets as a condition of market-based rate authority; (2) complying with the national treatment requirements of NAFTA; and (3) applying principles of comity to the jurisdiction of foreign regulatory authorities with direct regulatory jurisdiction over foreign transmission entities.[1152] Accordingly, NL Hydro believes that the Commission should codify in its regulations the requirement that a market-based rate seller, or its affiliate, that owns, controls, or operates transmission facilities outside of the United States must demonstrate that non-discriminatory access is offered on those facilities so that competitors of the seller may reach United States markets.

Commission Determination

1006. We will continue to require a seller seeking market-based rate authority that is a foreign utility or is affiliated with a foreign utility to affirmatively demonstrate that any owned or affiliated transmission is offered on a non-discriminatory basis that can be used by competitors of the seller or its affiliate to reach United States markets. Accordingly, we reject Powerex's suggestion that the Commission should presume that foreign transmitting utilities are providing comparable and not unduly discriminatory or preferential transmission service unless this presumption is rebutted. The Commission did not propose to implement section 211A of the FPA in Order No. 890 and section 211A is not relevant to the Commission's analysis for purposes of granting or denying market-based rate authority.[1153]

1007. We will codify in § 35.37(d) of the Commission's regulations the requirement that a market-based rate seller affiliated with a foreign utility, or its affiliate, that owns, controls, or operates transmission facilities outside of the United States and is interconnected with the United States must demonstrate that comparable, non-discriminatory access is offered on those facilities so that competitors of the seller may reach United States markets.

3. Change in Status

Commission Proposal

1008. In early 2005, the Commission clarified and standardized market-based rate sellers' reporting requirements for any change in status that departed from the characteristics the Commission relied on in initially authorizing sales at market-based rates. In Order No. 652,[1154] the Commission required, as a condition of obtaining and retaining market-base rate authority, that sellers file notices of such changes no later than 30 days after the change in status occurs. In the NOPR, the Commission sought comment on a number of issues that the Commission identified in Order No. 652 as issues that could be pursued in this proceeding. The Commission solicited comment on whether ownership of any new inputs to electric power production, including fuel supplies, should be reportable. To the extent that any such information is deemed reportable, the Commission proposed to align this reporting requirement to reflect the consideration of other barriers to entry as part of the vertical market power analysis.

1009. The Commission proposed, consistent with Order No. 652, not to require the reporting of transmission outages per se as a change in status. However, to the extent a transmission outage affects on a long-term basis whether the seller satisfies the Commission's concerns regarding horizontal or vertical market power, a change of status filing would be required. The Commission sought comment on this proposal.

[1146] NL Hydro is a Crown Corporation owned by the Government of Newfoundland and Labrador.

[1147] 16 U.S.C. 824j–1(b).

[1148] OATT NOPR at P 111.

[1149] Powerex at 32.

[1150] NL Hydro reply comments at 3.

[1151] *Id.* at 5.

[1152] NL Hydro at 13.

[1153] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 192.

[1154] Order No. 652 at P 47.

The Commission declined in Order No. 652 to narrow or delineate the definition of control. The Commission concluded that it is not possible to predict every contractual agreement that could result in a change of control of an asset; however, the Commission indicated that to the extent that parties wish to propose specific definitions or clarifications to the Commission's historical definition of control, they may do so in the course of the instant rulemaking.[1155]

1010. As proposed in the NOPR (§ 35.43 of the proposed regulations), events that constitute a change in status include the following: First, ownership or control of generation capacity that results in net increases of 100 MW or more, or of transmission facilities, or of inputs to electric power production other than fuel supplies; or, second, affiliation with any entity not disclosed in an application for market-based rate authority that owns, operates, or controls generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area.[1156] The Commission invited comment generally on whether the Commission should expand the triggering events for a change in status filing beyond what was adopted in Order No. 652. In Order No. 652, we concluded that the reporting obligation should extend only to changes in circumstances within the knowledge and control of the seller.

a. Fuel Supplies

Comments

1011. Some commenters in general support the idea that ownership of fuel supplies should not be a factor in the vertical market power analysis and should not trigger a requirement to file a notice of change in status.[1157] APPA/TAPS support the reporting of the acquisition of the means of production or transportation of fuel but not the reporting of the acquisition of fuel itself. APPA/TAPS explain that acquisition or control over companies that produce or deliver fuel and acquisitions of, or affiliations (including through joint ventures) with, production or transportation resources (including LNG facilities) are inputs into electric power production that can raise significant competitive concerns. APPA/TAPS submit that, unlike fuel, the means of production or transportation of fuel are not so readily obtainable from alternative sources.[1158] They argue that while entry from new storage or transportation facilities/transporters is possible, such entry involves sufficient siting difficulties and capital requirements that it cannot be assumed to be timely, likely or sufficient to remove competitive concerns.

1012. Constellation suggests that the Commission should clearly distinguish between fuel supplies (including the capacity to produce and process them) and physical facilities used to transport or distribute fuel supplies. Constellation believes that ownership of fuel supply does not contribute to market power because of the availability of alternative suppliers. Constellation states that, while ownership or control of physical facilities to transport or distribute fuel has the potential to contribute to market power in some cases, such potential generally is blunted by regulation or by the availability of substitutes. Constellation asserts that ownership of facilities for the production or processing of coal or other fuels should not be reportable because alternative sources of supply can substitute for the coal or other fuels that can be produced or processed by such facilities. Constellation states that in specific instances, if any intervenor believes that fuel supplies (or fuel production or processing facilities) are not available from alternative suppliers for delivery in the relevant geographic region, the party could provide appropriate information in an attempt to rebut a market-based rate seller's statement that it cannot erect barriers to entry in relevant markets.[1159]

1013. Constellation believes that the purchase of natural gas transportation or storage on intrastate or interstate pipelines should not trigger any change in status reporting requirement. It states that these transactions do not involve ownership or control of physical facilities for the transportation or storage of natural gas. Moreover, because capacity is available from the natural gas transportation and storage providers themselves, and through capacity release programs from other customers of such providers, Constellation believes that the purchase of such capacity does not contribute to the seller's vertical market power.[1160]

Commission Determination

1014. The Commission will not expand the change in status reporting requirement to include the reporting of a change in ownership or control of natural gas and oil supplies, or affiliation with an entity that owns or controls such fuel supplies. However, we will require the reporting of a change in status with regard to the ownership or control of, or affiliation with, any entity not disclosed in the application for market-based rate authority that owns, or controls ''inputs to electric power production,'' where that term is defined as ''intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and railcars.'' The Commission adopts this approach to align the change in status reporting requirement to reflect the other barriers to entry part of the vertical market power analysis.

1015. We will adopt the current change in status requirement with the following modifications.[1161] We will delete the phrase ''other than fuel supplies'' from proposed § 35.43(a)(1) (now § 35.42(a)(1)). We originally proposed that events that constitute a change in status include ''[o]wnership or control of generation capacity that results in net increases of 100 MW or more, or transmission facilities or inputs to electric power production other than fuel supplies.'' In light of the definition of ''inputs to electric power production'' that we adopt in this Final Rule, there is no longer a need in § 35.42(a)(1) for the phrase ''other than fuel supplies.'' As noted above in the discussion on vertical market power, in this Final Rule we modify the definition of ''inputs to electric power production'' to mean ''intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and railcars.'' The definition of ''inputs to electric power production'' includes ''sources of coal supplies,'' and therefore, including the phrase ''other than fuel supplies'' would be inaccurate. However, we note that the ownership or control of certain other fuel supplies (*i.e.*, gas and oil supplies) will not require a notice of change in status.

1016. Next, we are modifying the change in status provisions to be consistent with the horizontal and vertical market power provisions which we are adopting. Section 35.42, as adopted herein, differs from the NOPR

[1155] *Id.* at P 47.

[1156] NOPR at P 179–182.

[1157] APPA/TAPS at 90–91; EEI at 21; Constellation at 23.

[1158] APPA/TAPS at 90–91, citing *San Diego Gas & Elec. Co.*, 83 FERC ¶ 61,199 (1998) (gas/electric merger).

[1159] Constellation at 24–25.

[1160] *Id.* at 25.

[1161] Another change to 18 CFR 35.42 is described above in the implementation section.

proposal in that we will require change in status notifications for changes in ownership or control of inputs to electric power production. Additionally, change in status notifications will be required for changes in operation, in addition to ownership and control, of transmission facilities. Similarly, we will require a change in status notification for affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation facilities or inputs to electric power production and any entity not disclosed in the application for market-based rate authority that owns, operates or controls transmission facilities.

1017. In response to APPA/TAPS, we clarify that the Commission's change in status requirements are intended to track the requirements embedded in the horizontal and vertical analysis as well as the affiliate abuse representations. As clarified in the other barriers to entry part of the vertical market power analysis described in this Final Rule, the Commission will not require an analysis or affirmative statement with regard to ownership or control of, or affiliation with, an entity that owns or controls natural gas and oil supplies, the interstate transportation of natural gas, or the transportation of oil. In contrast, we will require a seller to provide a description of its ownership or control of, or affiliation with, an entity that owns or controls intrastate natural gas transportation; intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies (defined as ''inputs to electric power production'' in the regulations); however, we adopt a rebuttable presumption that sellers cannot erect barriers to entry with regard to inputs to electric power production. Thus, while a seller is required to describe in a change in status filing any ownership of, control of or affiliation with entities that own or control inputs to electric power production (just as it must do in an initial application for market-based rate authority and an updated market power analysis), we will rebuttably presume that such ownership, control or affiliation does not allow a seller to raise entry barriers. We will, however, allow intervenors to demonstrate otherwise.

1018. Further, in response to Constellation, we note that we presently do not require the reporting of capacity contracted for, but for which control is not transferred, with regard to interstate or intrastate natural gas pipeline or storage capacity and we agree that there is no compelling reason to begin doing so.

b. Transmission Outages

Comments

1019. Numerous commenters support the Commission's current policy and proposal not to require the reporting of transmission outages per se as a change in status.[1162]

1020. Some commenters support the proposal not to require the reporting of all transmission outages per se because they believe that requiring sellers to report all transmission outages as changes in status would prove an overwhelming administrative burden with no market benefits.[1163] Indianapolis P&L states that this approach balances the need for the Commission to have updated information with the need for sellers to focus on their business, rather than administrative filings.[1164] EEI supports the current policy that only long-term transmission outages that could affect the Commission's analysis of vertical and horizontal market power should be reportable.[1165]

1021. APPA/TAPS state that at least some transmission outage information is (or should be) publicly available on OASIS sites, suggesting less of a need to impose a separate reporting requirement for such outages.[1166] However, APPA/TAPS urge that certain outages be reported to the Commission's Office of Enforcement on a non-public basis and that the Commission reserve its authority to require change of status reports for other, significant outages.[1167] We note, however, that APPA/TAPS fail to provide examples of the types of outages that they believe should be reportable.

1022. APPA/TAPS also suggest that the Commission identify for specific market-based rate sellers generation and transmission facilities that, if there is an extended or repeated outage, could produce significant transmission constraints or reductions in the amount of available generation in that seller's market(s). They suggest that the Commission, in conjunction with an RTO/ISO market monitor (where one exists), could identify and designate in that seller's market-based rate authorization the key transmission facilities and/or generation units that are likely to increase competitive concerns if they go out of service. Because of the increased potential for market power harm associated with the outage of these facilities, APPA/TAPS suggest that the Commission could require a market-based rate seller under the terms of its market-based rate authorization to report publicly as a change in status outages of these specified facilities.[1168]

1023. Powerex believes that additional clarification is necessary to determine what the Commission means by ''long-term outages'' that may affect a seller's market power analysis. Powerex also requests that the Commission consider whether transmission outages on a non-jurisdictional or foreign affiliate's transmission system should be considered a change in status that is reportable under Order No. 652, given the limits of the Commission's jurisdictional interests.

Commission Determination

1024. We adopt the NOPR proposal not to require the reporting of transmission outages per se as a change in status. We agree that the reporting of all transmission outages, including the most routine, would be an excessive burden on sellers with no apparent countervailing benefit. However, consistent with Order No. 652, we reiterate that to the extent a long-term transmission outage affects one or more of the factors of the Commission's market-based rate analysis (*e.g.*, if it reduces imports of capacity by competitors that, if reflected in the generation market power screens, would change the results of the screens from a ''pass'' to a ''fail''), a change of status filing is required.[1169]

1025. We reject APPA/TAPS's suggestion that the Commission should require the automatic reporting of some transmission outages to the Office of Enforcement. APPA/TAPS fails to adequately explain why we should assume certain transmission outages are, as a matter of routine, an enforcement matter to be investigated for wrongdoing.

1026. We also reject APPA/TAPS' suggestion that the Commission identify certain generation and transmission facilities that could produce significant transmission constraints or reductions in the amount of generation available in

[1162] APPA/TAPS at 87–89; Indianapolis P&L at 15; EEI at 21; MidAmerican at 35–36; and Powerex at 34.

[1163] MidAmerican at 36; Indianapolis P&L at 15; EEI at 21.

[1164] Indianapolis P&L at 15.

[1165] EEI at 21.

[1166] APPA/TAPS at 88.

[1167] *Id.* at 87–88.

[1168] APPA/TAPS at 88–89.

[1169] In response to Powerex's request for clarification on what the Commission means by ''long-term outages'' that may affect a seller's market power analysis, we clarify that the Commission uses the term ''long-term'' to mean one year or longer.

that market-based rate seller's market(s). Public identification of such generation and transmission facilities could cause CEII and security concerns. In addition, outages that could affect a seller's market-based rate analysis will change over time. The burden remains on the market-based rate seller to identify the outages that should be reported as a change in status. We also remind commenters that entities may file a complaint or call the Office of Enforcement hotline if they are concerned that an outage provides the opportunity for a seller to exercise market power. Regarding Powerex's request that the Commission consider whether transmission outages on a non-jurisdictional or foreign affiliate's transmission system should be considered reportable under Order No. 652, given the limits of the Commission's jurisdictional interests, we clarify that, consistent with our change in status reporting requirement in general, to the extent that a transmission outage reflects a change in the characteristics that the Commission relied on (*e.g.*, if it reduces imports of capacity by competitors that, if reflected in the generation market power screens for U.S. markets, would change the results of the screens from a ''pass'' to a ''fail''), a change of status filing would be required. The change in status requirement is an important element of the Commission's market power oversight. If a seller affiliated with a foreign utility wishes to retain market-based rate authority in the United States, such seller must comply with the notice of change in status requirements, including the reporting of transmission outages that may change the results of the screens from a ''pass'' to a ''fail.'' The Commission finds no reason to exempt a seller affiliated with a foreign utility from this requirement.

c. Control

Comments

1027. Several commenters note that increased precision in the Commission's definition of control would be particularly helpful to sellers, especially in light of the increased emphasis on reporting accuracy and completeness and the Commission's general practice of accepting change in status filings in letter orders, without providing much detailed analysis or explanation as to whether the filings were required in the first place.[1170] These commenters seek clarification that energy contracts that are not associated with a specific resource (do not specify a ''source'') do not transfer control. EEI and SoCal Edison argue that such contracts or liquidated damages call option contracts do not transfer control because, at their core, they are financial transactions used to mitigate the buyer's price risk.[1171] According to commenters, the option holder does not actually control any particular capacity that might be used to meet the contract needs. The energy could come from the seller, from the market through the seller, or directly from the market to the buyer if the seller opts to pay liquidated damages. They submit that if such a contract were deemed to transfer ''control,'' execution of such routine contracts would trigger a change in status filing for each incremental 100 MW purchased thereby, which is most likely not what the Commission intended.

1028. APPA/TAPS support a reporting obligation for all of the types of contractual arrangements that could confer control, as consistent with the discussion in the horizontal market power section of the NOPR. They argue that these arrangements could provide a market-based seller with the means to determine whether capacity is offered into a market and whether a competitor can or will enter a market. They state that these arrangements also create opportunities for sellers to coordinate their behavior with other competitors. If the contracts do not raise competitive concerns, the seller could explain the factors supporting that conclusion in its report.[1172]

1029. SoCal Edison urges the Commission to consider whether, and to clarify how, the emerging, non-traditional capacity and electrical energy products that are routinely transacted in hybrid electricity markets today would fit within its construction of its test for control (''* * * affecting ability of the capacity to reach the relevant market''). It warns that buyers may be hesitant to routinely purchase products that require continual change in status filings.[1173]

Commission Determination

1030. Pursuant to the change in status reporting requirement, a market-based rate seller is required to report a change in control to the extent the seller acquires a net 100 MW or more generation capacity through contract. Our determination of what constitutes control is discussed above in the horizontal market power analysis section and we adopt that discussion for purposes of the change in status requirement. That is, the Commission concludes that the determination of control is appropriately based on a review of the totality of circumstances on a fact specific basis. No single factor or factors necessarily results in control. If a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller for purposes of complying with the change in status requirement.

1031. Further, as the Commission has previously clarified, sellers making a change in status filing to report an energy management agreement are required to make an affirmative statement in their filing as to whether the agreement at issue transfers control of any assets and whether the agreement results in any material effect on the conditions that the Commission relied upon for the grant of market-based rate authority. On some occasions, and at the Commission's discretion, the Commission may request the seller to submit a copy of the agreement and provide supporting documentation.[1174]

1032. We reiterate here that a seller making a change in status filing is required to state whether it has made a filing pursuant to section 203 of the FPA.[1175] To the extent the seller has made a section 203 filing that it submits is being made out of an abundance of caution without conceding that the Commission has section 203 jurisdiction, the seller will be required to incorporate this same assumption in its market-based rate change in status filing (*e.g.*, if the seller assumes that it will control a jurisdictional facility in a section 203 filing, it should make that same assumption in its market-based rate change in status filing and, on that basis, inform the Commission as to whether there is any material effect on its market-based rate authority).[1176]

d. Triggering Events

Comments

1033. In the NOPR, the Commission invited comments on whether it should expand the triggering events for a change in status filing beyond

[1170] EEI at 21–22; SoCal Edison at 10–14; Williams at 1; and Powerex at 33.

[1171] EEI offers an example of a firm energy call option that, in response to a day-ahead call by the buyer, gives the seller the option of delivering energy from its own facilities or buying energy from the competitive market, with the obligation to pay liquidated damages equal to the difference in price between the pre-agreed price and the cost to the buyer of buying replacement power from another source for failure to deliver. EEI argues such contract should not be deemed to transfer ''control'' and therefore should not be reportable.

[1172] APPA/TAPS at 89.

[1173] SoCal Edison at 14–16.

[1174] *Calpine Energy Services, L.P.*, 113 FERC ¶ 61,158 at P 13 (2005) (*Calpine*).

[1175] 16 U.S.C. 824b.

[1176] *Calpine,* 113 FERC ¶61,158 at P 14.

ownership or control of facilities or inputs and affiliation with entities that own or control facilities or inputs or that have a franchised service territory, as set forth in Order No. 652. No commenters suggest additional triggering events, and several commenters oppose any general expansion of categories.[1177] Several commenters specifically oppose any requirement to report actions taken by competitors or natural events as a change in status. They argue that, in many cases, the seller may be unaware of actions taken by a competitor, making compliance virtually impossible.[1178]

Commission Determination

1034. We will not expand the events that trigger a change in status filing. Further, we will not expand triggering events to include actions taken by a competitor (such as a decision to retire a generation unit or take transmission capacity out of service) or natural events (such as hydro-year level, higher wind generation, or load disruptions due to adverse weather conditions) beyond those adopted in Order No. 652. As we describe above in the vertical market power analysis discussion, with regard to barriers to entry erected or controlled by other than the seller, we find that it is not reasonable to routinely require sellers to make a showing regarding potential barriers to entry that others might erect and that are beyond the seller's control. However, we will entertain on a case-by-case basis claims that the existence of barriers to entry beyond the seller's control may affect the seller's ability to exercise market power. For similar reasons we will not expand the events that trigger a change in status filing to include actions taken by a competitor or natural events. However, we will entertain on a case-by-case basis claims that such actions may affect the seller's ability to exercise market power.

e. Timing of Reporting

Comments

1035. At present, the Commission requires the reporting of changes in status to be ''filed no later than 30 days after the legal or effective date of the change in status, including a change in ownership or control, whichever is earlier.'' [1179] The proposed regulatory text maintains this requirement.

1036. CAISO supports the current requirement that entities with market-based rate authority must report changes of status no later than 30 days after the change has occurred. CAISO proposes that any change in status be reported not only to the Commission but also to the relevant market monitor where the facilities are located. CAISO states that this minimal additional burden on the supplier will ensure that RTO and ISO staff are operating with the latest possible information.[1180]

1037. SoCal Edison recommends that the Commission revise the change in status reporting requirement to focus upon the actual acquisition of the resources in question—for power sales contracts, the date of physical power delivery. SoCal Edison states that the Commission's current policies make it virtually impossible for a seller to provide a meaningful evaluation of whether or not a forward contract with delivery months or years in the future creates a departure from the characteristics the Commission relied upon in granting market-based rate authority as much as three years previously. SoCal Edison notes that, as currently written, the policy requires reporting of procurement activities potentially years in advance of any power delivery because the effective date of the contract—usually the execution date—may significantly precede the date of physical delivery—that is, the actual transfer of control over generation resources.[1181]

Commission Determination

1038. We provide clarification regarding when a change in status filing should be filed. In Order No. 652, we determined that reports of changes in status must be filed no later than 30 days after the legal or effective date of the change in status, including a change in ownership or control, whichever is earlier.[1182] However, it was not the Commission's intention, as SoCal Edison notes, to require reporting of procurement activities potentially years in advance of any power delivery. We agree with SoCal Edison that the current policy may be unclear and may cause an entity to file a notice of change in status years in advance of the actual transaction, *i.e.*, change in ownership or transfer of control. The Commission requires a meaningful evaluation of whether a change creates a departure from the characteristics the Commission relied upon in granting market-based rate authority. It would be difficult for the Commission to accurately evaluate whether or not, for example, a forward contract with delivery months or years in the future will affect the conditions the Commission relied upon for the market-based rate authorization. Accordingly, we will modify § 35.42(b) (formerly § 35.43(b)) to provide that, in the case of power sales contracts with future delivery, such contracts are reportable 30 days after the physical delivery has begun.

1039. We reject CAISO's proposal that any change in status also be reported to the relevant market monitor where the facilities are located. We find that informing the Commission of changes in status is sufficient. Change in status filings are noticed and therefore interested entities will have notice of any such filing.

f. Sellers Affiliated With a Foreign Utility

1040. The change in status requirement is applicable to all market-based rate sellers regardless whether they are domestic or affiliated with a foreign utility.

Comments

1041. Powerex notes that the Commission stated in the NOPR that it ''does not consider transmission and generation facilities that are located exclusively out of the United States and that are not directly interconnected to the United States [but] would consider transmission facilities that are exclusively outside the United States but nevertheless interconnected to an affiliate's transmission system that is directly interconnected to the United States.'' [1183] Powerex submits that the NOPR fails to clarify the Commission's proposed treatment of foreign-sited generation facilities interconnected to an affiliated transmission system that, in turn, is directly interconnected to the United States transmission grid. Powerex argues that, based on the nature of the Commission's concerns with respect to facilities outside the United States, the details concerning such generation capacity should not be relevant to the Commission's determination in circumstances where the affiliated uncommitted capacity exceeds the transmission limits of the intertie(s) directly interconnecting the affiliated foreign transmission system to the United States grid. Powerex states that foreign sellers with foreign generating facilities can make that generation available to United States

[1177] MidAmerican at 36; Powerex at 34.

[1178] MidAmerican at 36–37; Powerex at 34.

[1179] Order No. 652 at P 106. The Commission clarified that for power sales contracts, ''it is irrelevant for the purposes of compliance with the reporting obligation if the effective date on which control is transferred occurs prior to the date on which the purchaser is contractually bound to commence physical delivery.'' Order No. 652–A at P 31.

[1180] CAISO at 15.

[1181] SoCal Edison at 17–19.

[1182] Order No. 652 at 106.

[1183] NOPR at P 175.

markets only to the extent that transmission capacity is available on the interties crossing the international boundaries. In such instances, Powerex argues that the seller's participation in United States jurisdictional markets is constrained by the total transfer capability (TTC) of the transmission system of the intertie (a measurement of the level of imports that can access a market from a particular location). Powerex asserts that those intertie limits represent the foreign seller's maximum uncommitted foreign capacity available to United States markets.[1184] Thus, according to Powerex, only changes in the TTC of the intertie itself should be considered a change in the circumstances upon which the original market-based rate authorization was based, for purposes of Order No. 652 filings.[1185]

1042. Powerex also argues that complying with the change in status requirements of Order No. 652 would require foreign sellers to demand routine updates of potentially non-public information from their foreign generation-owning affiliates; it contends that Order No. 652 imposes a continuous updating requirement any time an affiliate acquires additional generation assets, re-rates an existing facility, or enters into third-party contracts that confer some degree of control.[1186] Powerex states that in certain circumstances, release of information could be inconsistent with the standards and policies of the foreign utility regulatory agency regulating the foreign generation owner.[1187] Powerex argues that concerns related to these types of frequently non-public changes to an affiliate's generation profile are appropriately limited to United States assets located in United States markets.

Commission Determination

1043. The Commission treats foreign-sited generation facilities interconnected to an affiliated transmission system that, in turn, is directly interconnected to the United States transmission grid in the same way that it treats the first-tier generation facilities of non-foreign sellers. For the purpose of determining total uncommitted capacity, the affiliates' capacity is combined.

1044. In response to Powerex, we agree that if the Commission's grant of market-based rate authority was based on the seller's, including its affiliate's, uncommitted capacity exceeding the transmission limits of the intertie(s) directly interconnecting the seller to the United States grid, only changes in the TTC of the intertie would be considered a change in status subject to a reporting requirement.

1045. Further, if a foreign utility believes that release of specific information is inconsistent with the policies of a foreign utility regulatory agency, the foreign utility should specifically inform the Commission of this, and the Commission will take the matter under advisement when considering whether to grant a request for special treatment.

4. Third-Party Providers of Ancillary Services

Commission Proposal

1046. In Order No. 888, the Commission required transmission providers to offer certain ancillary services at cost-based rates as part of their open access commitment but also contemplated that third parties (parties other than the transmission provider in a particular transaction) could provide certain ancillary services.[1188] The Commission also left open the door for ancillary services to be provided on other than a cost-of-service basis. In Order No. 888, the Commission stated that it would entertain requests for market-based pricing related to ancillary services on a case-by-case basis if supported by analyses that demonstrate that the seller lacks market power in these discrete services.[1189]

1047. In *Ocean Vista Power Generation, L.L.C.,*[1190] the Commission explained that, as a general matter, a study of ancillary service markets should address the nature and characteristics of each ancillary service, as well as the nature and characteristics of generation capable of supplying each service, and that the study should develop market shares for each service. In particular, the Commission stated that an individual seller's market power analysis for ancillary services markets should: (1) Define the relevant product market for each ancillary service; (2) identify the relevant geographic market, which could include all potential sellers of the product from whom the buyer could obtain the service, taking into account relevant factors which may include the other sellers' locations, the physical capability of the delivery system and the cost of such delivery, and important technical characteristics of the sellers' facilities; (3) establish market shares for all suppliers of the ancillary services in the relevant geographic markets; and (4) examine other barriers to entry. The Commission also noted that it would entertain alternative explanations and approaches.

1048. The Commission adopted in *Avista Corporation*[1191] a general policy stating that third-party ancillary service providers that could not perform a market power study would be allowed to sell ancillary services at market-based rates, but only in conjunction with a requirement that such third parties establish an Internet-based OASIS-like site for providing information about and transacting ancillary services. The authorization in *Avista* extended only to the following four ancillary services: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves. The Commission based its *Avista* policy on the expectation that, as entry into ancillary service markets occurs, prices will decrease from the level established by the transmission provider's cost-based rate. Under these circumstances, customers will pay prices for ancillary services that are no higher than and will very likely be lower than the transmission provider's cost-based rate. The Commission explained that the ancillary services customer is protected in part by the availability of the same ancillary services at cost-based rates from the transmission provider. The backstop of cost-based ancillary services from the transmission provider provides, in effect, a limit on the price at which customers are willing to buy ancillary services.[1192]

1049. To further monitor market entry, the Commission required third-party suppliers to file with the Commission one year after their Internet-based site was operational (and at least every three years thereafter) a report detailing their activities in the ancillary services market.[1193]

1050. The Commission stated that it would apply this policy only to sellers that are authorized to sell power and energy at market-based rates. In addition, the Commission stated that it

[1184] Powerex at 29–30.

[1185] *Id.* at 30.

[1186] *Id.* at 31.

[1187] Powerex at 31.

[1188] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720–21.

[1189] *Id.*; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,237–38.

[1190] 82 FERC ¶ 61,114 at 61,406–07 (*Ocean Vista*).

[1191] 87 FERC ¶ 61,223, *order on reh'g,* 89 FERC ¶ 61,136 (1999) (*Avista*).

[1192] We note that the Commission has authorized several utilities to use market index pricing for energy imbalance service. *See, e.g., PacifiCorp,* 95 FERC ¶ 61,145 (2001), *order on reh'g,* 95 FERC ¶ 61,467 (2001). In such a case, customers are protected by the transmission provider's obligation to offer the service at rates the Commission determines are just and reasonable and consistent with our *Avista* policy.

[1193] The Commission subsequently established an EQR requirement for all market-based rate sellers.

would not apply this approach to sales of ancillary services by a third-party supplier in the following situations: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties;[1194] (2) to address affiliate abuse concerns, sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.[1195]

1051. In the NOPR, the Commission proposed to retain the *Avista* policy but sought comment on whether to modify or revise that current approach and, if so, how. The Commission also sought comment on whether its current conditions, such as the requirement to establish an Internet-based site, continue to be necessary.

a. Internet Postings and Reporting Requirements

Comments

1052. A number of commenters support modifications to the Commission's current approach to third-party sales of ancillary services on the basis that they believe the current policy has not succeeded in engendering robust markets for ancillary services. Avista, Puget, Cogentrix and Powerex state that the existing Internet posting and reporting policy is unnecessary.[1196] Avista and Puget note that the current EQR requirement, which did not exist when the Commission first adopted the Internet posting requirement, provides sufficient information for the Commission to monitor ancillary services markets for market power. They argue that abandoning the Internet posting and reporting conditions would contribute to the development of more robust reserves markets. Similarly, Cogentrix and Powerex maintain that those requirements are burdensome and hard to implement, especially for independent sellers that are not transmission owners and do not have the responsibility to maintain an OASIS. Instead of safeguarding against possible abuses of market power, these commenters state that the posting and reporting requirements have probably hindered the development of robust markets for ancillary services.

1053. Puget states that virtually all ancillary services outside of RTO/ISO markets are provided at cost-based rates by the host transmission provider. Puget states that it conducted a review of the reports filed in dockets in which the Commission has granted market-based rate authority to sell ancillary services under the *Avista* provisions, which revealed that only a handful of ancillary services sales have been made. Based on the small number of market-based ancillary services sales that Puget found in its review of existing dockets, it concludes that companies have determined that the potential commercial gains from entering this market do not justify the cost and risks associated with the special posting and reporting requirements.

1054. Avista and Powerex state that, to the extent that the Commission is concerned about market power, purchasers of ancillary services are protected from the exercise of market power because they may purchase these services from the transmission provider at cost pursuant to the OATT. Powerex maintains that the Commission can monitor these transactions via the EQRs and can encourage purchasers to file complaints under FPA section 206 should they believe a seller has exercised market power when making such sales.

1055. In contrast, APPA/TAPS urge the Commission not to relax standards for market-based pricing of ancillary services. They support continuation of the Commission's current approach for pricing ancillary services, including the requirement for a cost-based backstop for ancillary services provided by a transmission provider. They argue that ancillary services markets remain very much dependent upon control area operation and are closely connected to the operations of the transmission system. APPA/TAPS state that locational reserves requirements limit the geographic scope of potential ancillary service suppliers, and that capacity on automatic generation control cannot easily sell regulation service in its home market today and switch to sales in an adjoining market tomorrow. Further, they state that customers cannot shop for such services. According to APPA/TAPS, limitations of transmission and technology counsel against adopting short-cuts for assessing the appropriateness of market-based pricing of ancillary services.[1197]

1056. Morgan Stanley supports efforts to establish market-based ancillary service markets both inside and outside of ISOs and RTOs. Morgan Stanley recommends that the Commission investigate what is necessary to establish local ancillary services markets on a nationwide basis. Morgan Stanley supports eliminating barriers to entry in the ancillary services market and states that to further this goal, the Commission should allow market participants to negotiate over-the-counter (OTC) ancillary services contracts outside of established ISOs and RTOs. Morgan Stanley mentions that this option should be open to all sellers with market-based rates and that the posting requirement should remain mandatory for mitigated entities.

Commission Determination

1057. We will modify our current approach for third-party sellers of ancillary services at market-based rates as announced in *Avista.* We appreciate the concerns raised by a number of commenters that the posting and reporting requirements imposed in *Avista* may be hindering the development of ancillary services markets particularly by third-party providers. As noted above, some commenters have indicated that the costs and responsibilities associated with establishing and maintaining an internet-based site may outweigh the benefits that third-party sellers could derive from the sale of the additional products. We conclude that our EQR filing requirement provides an adequate means to monitor ancillary services sales by third parties such that the posting and reporting requirements established in *Avista* are no longer necessary. Through their EQR filings, third-party providers of ancillary services provide information regarding their ancillary services transactions for the quarter, including the ancillary service provided, the price, and the purchaser. As a result, we will no longer require third-party providers of

[1194] With the formation of RTOs and ISOs, several RTOs/ISOs performed market analyses to demonstrate whether various ancillary services are competitive. The result has been as follows: California Independent System Operator: Regulation, Spinning Reserve, and Non-Spinning Reserve. ISO New England: Regulation and Frequency (Automatic Generation Control), Operating Reserve—Ten-Minute Spinning, Operating Reserve—Ten-Minute Non-Spinning, and Operating Reserve—Thirty Minute. New York Independent System Operator: Regulation and Frequency Response Service, Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves). PJM Independent System Operator: Regulation and Frequency Response, Energy Imbalance, Operating Reserve—Spinning, and Operating Reserve—Supplemental. Thus, in markets where the demonstration has been made, sellers are afforded the opportunity to sell at market-based rates subject to any other conditions in those markets.

[1195] *Avista,* 87 FERC at 61,883, n.12.

[1196] Avista at 7–8; Puget at 1, 4–8; Cogentrix at 8–10; Powerex at 35–38; Morgan Stanley at 11–12.

[1197] APPA/TAPS at 91.

ancillary services to establish and maintain an internet-based OASIS-like site for providing information about their ancillary services transactions.

1058. In addition, we will no longer require third-party suppliers to file with the Commission one year after their internet-based site is operational (and at least every three years thereafter) a report detailing their activities in the ancillary services market. We note that the Commission retains the ability to require such a report by a third-party supplier of ancillary services at any time.

1059. All sellers that seek authority to sell ancillary services at market-based rates pursuant to *Avista* [1198] must make a filing with the Commission to request that authority and must include language in their market-based rate tariffs identifying the ancillary services that they offer.[1199]

1060. Moreover, we will retain our current policy of not allowing sales of ancillary services by a third-party supplier in the following situations: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.[1200] These standard applicable tariff provisions appear in Appendix C to this Final Rule. As we stated in *Avista,* we are open to considering requests for market-based rate authorization to make such sales on a case-by-case basis.

1061. At this time, the Commission will not adopt Morgan Stanley's recommendation to investigate what is necessary to establish local ancillary services markets on a nationwide basis. We believe that the elimination of certain reporting requirements for third party providers of ancillary services adopted herein will adequately balance the need to encourage the development of ancillary services markets and the Commission's responsibility to provide oversight and protection from market power. We find Morgan Stanley's suggestion that the Commission allow market participants to negotiate OTC ancillary services contracts outside of established RTO/ISO markets unsupported and lacking in detail.[1201]

b. Pricing for Ancillary Services in RTOs/ISOs

Comments

1062. As noted above, the Commission stated in Order No. 888 that it would entertain requests for market-based pricing related to ancillary services on a case-by-case basis if supported by analyses which demonstrate that the seller lacks market power in these discrete services.[1202] To date, the Commission has permitted market-based rate pricing for certain ancillary services in a number of RTOs and ISOs.[1203] Although Ameren supports retaining the Commission's current approach, Ameren urges the Commission to address what it describes as a critical market design flaw regarding pricing for ancillary services in RTO/ISO markets with Day 2 energy markets but no market for ancillary services, such as the Midwest ISO. Ameren explains that providing regulation service and spinning reserves in the Midwest ISO market at traditional cost-based rates is uneconomic at present because owners of ancillary services capacity generally find it more profitable to sell energy from the capacity at market-based rates rather than to offer the capacity as reserves at cost-based rates. Ameren recommends that the Commission ensure that its approach to sales of ancillary services provides flexibility by allowing sellers for cost-based rates for regulation service and spinning reserves in the Midwest ISO footprint to propose a component for recovery of lost opportunity costs where such costs are shown to be legitimate and verifiable. Ameren submits that the Commission has recognized the need for opportunity cost recovery in other circumstances, and should consider an opportunity cost component in the future.[1204]

1063. CAISO states that it agrees with the Commission's decision to distinguish sales within an RTO or ISO from those not within an RTO or ISO.[1205] It agrees that the Commission can rely on the market monitoring unit of the RTO or ISO to assess competitiveness in the RTO or ISO's ancillary service markets.[1206]

1064. However, CAISO also notes that the size of the ancillary service market is subject to change based on system conditions and the need to meet applicable reliability criteria. It says that at times the CAISO may be able to procure ancillary services on a system-wide basis, whereas at other times factors such as the proportionate mix of hydro and thermal resources, transmission path operating transfer capability limits or deratings, forecasted path flows, anticipated load and weather conditions, and generator outages may require the CAISO to procure ancillary services on a zonal or even more location-specific basis. CAISO also states that because not every facility has the capability to provide every ancillary service, the market power analysis for the energy market does not automatically ensure that market power cannot be exercised with respect to sales of ancillary services. Accordingly, CAISO states that there may be the need for more targeted market power mitigation procedures specifically applicable to sales of ancillary services.

1065. NYISO supports the Commission's proposed approach to the extent it is predicated on all eligible sellers being able to benefit from the Commission's authorization of the NYISO to purchase ancillary services for loads at market-based rates.[1207] It states that all eligible sellers should receive the market-clearing prices for ancillary services that are supplied on a market basis and that the final regulations should not impose burdensome and duplicative market data requirements on a potential seller of ancillary services, either directly or through data demands to an ISO if the ISO has already received

[1198] As noted above, the *Avista* policy applies to the following four ancillary services: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves.

[1199] Sellers that have been granted authority to provide third-party ancillary services need not reapply because their authority continues.

[1200] *Avista,* 87 FERC at 61,883, n. 12.

[1201] Morgan Stanley's comments provide an insufficient basis for us to determine whether such OTC ancillary services contracts would be jurisdictional. The Commission has previously stated that it is not concerned with management transactions (such as swaps, options, and futures contracts) designed to assist buyers and sellers of electricity in hedging against adverse price changes which are settled in cash and where parties do not take actual delivery of the electricity. *Morgan Stanley Capital Group, Inc.,* 69 FERC ¶ 61,175 (1994).

[1202] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,656–57; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,230.

[1203] *AES Redondo Beach, L.L.C., et al.,* 85 FERC ¶ 61,123 (1998), *order on reh'g,* 87 FERC ¶ 61,208 (1999), *order on reh'g and clarification,* 90 FERC ¶ 61,036 (2000); *New England Power Pool,* 85 FERC ¶ 61,379 (1998), *reh'g denied,* 95 FERC ¶ 61,074 (2001); *Central Hudson Gas & Electric Corporation, et al.,* 86 FERC ¶ 61,062, *order on reh'g,* 88 FERC ¶ 61,138 (1999).

[1204] Ameren at 24–25, citing *San Diego Gas & Elec. Co.,* 95 FERC ¶ 61,115 at 61,363–64 & n.47 (2001).

[1205] CAISO at 16–18.

[1206] CAISO recommends that the Final Rule emphasize the importance of appropriate RTO or ISO market power mitigation tariff provisions for sales involving ancillary services.

[1207] NYISO at 10.

Commission authorization for market-based ancillary services.

1066. APPA/TAPS urge caution for market-based pricing of ancillary services in RTO/ISO areas. Even if the Commission finds that conditions exist to permit market-based pricing of some ancillary services in some RTO/ISO-administered markets, APPA/TAPS state that such pricing would not be appropriate where vertically integrated utilities are also control area operators, such as in Midwest ISO and SPP, because the locational, control-area dependent nature of ancillary services increases the risk that control area operators will have market power.[1208]

1067. Powerex recognizes that in some control areas, there are locational reserve requirements that can be met by a limited number of resources and therefore limit the geographic scope of potential suppliers.[1209] Powerex believes, however, that this situation can be mitigated on a case-specific basis, and therefore that it should not be the basis for generally rejecting the benefits of competitive supply of ancillary services. Powerex believes that it is the combination of the Commission's existing regulatory framework and administrative barriers raised by transmission providers that has effectively stifled the incentives for third-party suppliers to participate in ancillary services markets.[1210] In support, Powerex states that experience with the California organized markets demonstrates that a third-party provider can sell operating reserves and regulation service services to an adjoining market and that these services can be provided from resources located two markets and more than a thousand transmission miles away.

Commission Determination

1068. We will continue our current approach regarding market-based pricing for certain ancillary services in RTOs and ISOs. Where an RTO or ISO performs a market analysis demonstrating a lack of market power for certain ancillary services, the Commission has approved the sale of those ancillary services at market-based rates. As reflected in the NOPR, the Commission has approved the sale of certain ancillary services at market-based rates in CAISO, ISO New England, NYISO, and PJM. Moreover, the Commission considers on a case-by-case basis market power mitigation measures for sales involving ancillary services in these markets.

1069. Ameren's request that the Commission address what Ameren considers to be a critical market design flaw regarding pricing for ancillary services in the Midwest ISO is beyond the scope of this rulemaking proceeding. Ameren's concerns are more appropriately addressed upon an appropriate record in the context of proceedings involving the Midwest ISO market.

1070. With regard to APPA/TAPS' concern that market-based pricing of ancillary services would not be appropriate where vertically integrated utilities are also balancing authority area operators, such as in Midwest ISO and SPP, we note that the Commission carefully analyzes ancillary service markets in ISOs and RTOs before authorizing market-based rate pricing, ensuring that protections, such as market monitors, are established to reduce the risk that market power can be exercised. APPA/TAPS has had the opportunity to intervene and participate in such proceedings, including in proceedings involving Midwest ISO and SPP.

1071. The Commission also imposes mitigation where necessary. For example, the Commission in its *PJM West/South Regulation Zone* order permitted sellers that lack market power in PJM to submit market-based rate bids in the market for regulation service, while mitigating bids submitted by American Electric Power Company and Virginia Electric and Power Company, because PJM has not sufficiently demonstrated that they lack the potential to exercise market power in this market.[1211]

5. Reactive Power and Real Power Losses

Commission Proposal

1072. In the NOPR, the Commission did not provide a proposal with regard to the treatment of reactive power and real power losses. However, several commenters submitted comments about these services.

a. Reactive Power

Comments

1073. Cogentrix asks the Commission to reconsider the existing requirements for the sale of reactive power by independent generators. It notes that currently generators can sell reactive power only upon the submission to the Commission of separate cost filings. Cogentrix submits that the requirement of cost justification of reactive power rates should be eliminated. Cogentrix states that this requirement is unnecessary because generators with market-based rate authority are found to lack market power and are subject to the EQR and change in status reporting requirements, which ensure that they continue to lack market power and, therefore, that they cannot dictate the pricing of reactive power services. Cogentrix submits that because reactive power is a service that purchasers require generators to provide, it should be left to the parties to negotiate the proper rate under the interconnection agreement or the power purchase agreement, without requiring the generator to submit additional cost filings.[1212]

Commission Determination

1074. We reject Cogentrix's proposal that the Commission reconsider in this proceeding existing requirements for the sale of reactive power by independent generators and eliminate the requirement that generators submit separate cost filings supporting reactive power sales. Consistent with our precedent,[1213] we will continue to analyze reactive power sales on a case-by-case basis.

b. Real Power Losses

Comments

1075. Powerex requests that the Commission explicitly permit sellers to offer third-party loss compensation services[1214] on non-affiliated transmission systems under their general market-based rate authority.[1215] Powerex states that it believes that third parties currently are making real power losses sales pursuant to their market-

[1208] APPA/TAPS at 92.

[1209] *See, e.g.*, APPA/TAPS at 90–92.

[1210] Powerex reply comments at 1–3.

[1211] *PJM Interconnection, L.L.C.*, 111 FERC ¶ 61,134 (2005) (*PJM West/South Regulation Zone*). Similarly, the Commission in *New York Independent System Operator, Inc.*, 91 FERC ¶ 61,218 at 61,798–802(2000), suspended market-based pricing in the non-spinning reserve market for a temporary period. The Commission imposed bidding restrictions on 10 minute non-spinning operating reserves suppliers and a mandatory bid requirement which required that all available capacity held by eastern suppliers of 10 minute non-spinning reserves, and that is not subject to a *bona fide* outage or conflicting contractual obligation, be bid into the market. The Commission indicated that the mandatory bid requirement was necessary to protect against the physical withholding of capacity for the 10 minute non-spinning reserve market.

[1212] Cogentrix at 10.

[1213] *See, e.g.*, *Calpine Oneta Power, L.P*, 119 FERC ¶ 61,177 (2007), and cases cited therein.

[1214] Although Powerex does not directly define loss compensation energy, we interpret it to be equivalent to real power losses associated with all transmission service. The Commission's *pro forma* OATT in Order No. 890, sections 15.7 and 28.5, refer to real power losses. For purposes of this Final Rule, we will refer to loss compensation service or energy as real power losses.

[1215] Powerex initial comments at 38–40.

based rate authority.[1216] Powerex believes that the provision of real power losses is no different than the provision of other energy. It notes that in some control areas, the provision of such services comes with other attendant duties such as acting as the scheduling party for the losses.

Commission Determination

1076. We agree with Powerex that the provision of real power losses is no different than the provision of other energy. We clarify that we permit sellers to offer third-party real power losses on non-affiliated transmission systems under their market-based rate authority.

V. Section-by-Section Analysis of Regulations

1. Section 35.27 Authority of State Commissions

1077. In the NOPR, we explained that the first two paragraphs of this section were added by Order No. 888, while Order No. 652 later added subsection (c) to implement the change in status reporting requirement. The Commission proposed to move or delete subsections (a) and (c), leaving only (b), which clarifies that nothing in this part should be construed as preempting or affecting the authority of State commissions. The NOPR did not propose to revise the language of subsection (b) in any way, and proposed only to amend the heading from ''Power Sales at Market-Based Rates'' to ''Authority of State Commissions.'' NASUCA filed comments in support of ''assuring that there will be no preemption of State prerogatives under the proposed new regulations * * *.''[1217]

1078. We reiterate that the Commission is not proposing to add or revise this provision at this time. It remains unchanged from when the Commission adopted it in Order No. 888. The fact that it is renumbered in this proceeding will not have any impact, positive or negative, on the prerogatives of State commissions.

2. Section 35.36 Generally

1079. This section defines certain terms specific to Subpart H and explains the applicability of Subpart H. Some of these terms were put in place when the Commission codified certain market behavior rules in Order No. 674.[1218]

1080. The NOPR proposed to define ''Seller'' in paragraph (a)(1) as a public utility with authority to, or seeking authority to, engage in sales for resale of electric energy at market-based rates in order to make clear that Subpart H deals exclusively with market-based rate power sales. NASUCA comments that the explanation for the definition of ''Seller'' does not mention any language in FPA section 205 regarding ''market-based rates,'' and further, that there is no reference to market-based rates in that section of the Act. Thus, NASUCA contends that ''the reference in the definition of ''seller'' to ''market-based rates under section 205 of the Federal Power Act'' is a *non sequitur*, lacks support in the statutory language, and should be deleted.''[1219]

1081. We do not agree that the limiting language should be deleted. We believe that it is essential that the regulations in subpart H apply only to the specific sales that we are regulating herein (*i.e.*, market-based rates for wholesale sales of electric energy, capacity and ancillary services by public utilities) and not to any sales made at cost-based rates or under any other authority; the definition should make this scope clear. To the extent that NASUCA is challenging the Commission's ability to authorize market-based rates at all, the Commission addresses NASUCA's arguments in that regard in the legal authority section of this Final Rule.

1082. In the NOPR, the Commission proposed definitions for Category 1 Sellers and Category 2 Sellers to assist in understanding the parameters of the updated market power analysis filing requirement. The definition of Category 1 Sellers is being clarified, consistent with the discussion above in Implementation Process.

1083. Paragraph (a)(4) defines inputs to electric power production in order to simplify § 35.37(e) regarding other barriers to entry. The Final Rule revises the definition consistent with the discussion in the vertical market power section.

1084. Paragraph (a)(5) indicates that where the term franchised public utility is used, it is meant to include only those public utilities with a franchised service obligation under State law. The Commission modifies the definition as proposed in the NOPR so that the term ''franchised public utility'' does not include only utilities with captive customers. Instead, throughout the final regulations, references to franchised public utilities with captive customers are explicitly identified, where applicable.

1085. New paragraph (a)(6) provides a definition of captive customers, the genesis of which is discussed above in the Affiliate Abuse section.

1086. Paragraph (a)(7) (which was proposed as § 35.36(a)(6) in the NOPR) provides a definition for market-regulated affiliated entities.

1087. New paragraph (a)(8) provides a definition of market information.

1088. Paragraph (b) is a basic description of the applicability of Subpart H.

3. Section 35.37 Market Power Analysis Required

1089. This section describes the market power analysis the Commission employs, as discussed in the preamble, and when sellers must file one. It is intended to identify the key aspects of the analysis.

1090. The Final Rule adds paragraph (a)(2), which codifies the requirement mentioned in the NOPR for each seller to include an appendix identifying specified assets with each market power analysis filed. The paragraph also directs readers to Appendix B for a sample asset appendix.

1091. New language in paragaphs (c)(2) and (c)(3) clarifies that both sellers and intervenors may file alternative evidence to support or rebut the indicative screens, and addresses the use of the Delivered Price Test and its role in the analysis of market power, respectively. Further, at paragraph (c)(4), the regulations codify the requirement that each seller use a standard format for the indicative screens, the use of which was proposed in the NOPR.

1092. Paragraph (d) specifies the requirement that a seller with transmission facilities must have on file an Open Access Transmission Tariff. The Final Rule adds a description of how this requirement applies to sellers affiliated with foreign utilities.

1093. Paragraph (e) describes the information that must be provided to demonstrate a lack of vertical market power. The text is revised in several respects reflecting the discussion in the section of the Final Rule on vertical market power.

[1216] Powerex cites to a filing in which Ameren stated its understanding that it ''may sell the energy that will be used by customers that choose to self-supply energy to meet their transmission losses to such customers under its general market-based power sales authority. [Ameren] will merely be selling the power the customer will use to meet its losses and obligations and, from [Ameren's] standpoint, this will be no different than any other power sale. Such sales are also consistent with the Commission's decision to treat the provision of losses as a service that can be provided by multiple entities, rather than one that the transmission provider is uniquely situated to provide.'' Powerex at 39, citing Letter Transmitting Compliance Filing, Ameren Energy Marketing Co., Docket No. ER01–1945, at n.3 (July 27, 2001).

[1217] NASUCA at 3–4.

[1218] *Conditions for Public Utility Market-Based Rate Authorization Holders*, Order No. 674, FERC Stats. & Regs. ¶ 31,208, 114 FERC ¶ 61,163 (2006).

[1219] NASUCA at 32.

1094. The Final Rule adds a new paragraph (f) to address concerns that CEII claims in market-based rate filings have been overbroad. The subsection provides a process for intervenors to gain access to data for which the filer has claimed privileged treatment under 18 CFR 388.112.

4. Section 35.38 Mitigation

1095. The regulatory text proposed in the NOPR did not propose specific changes to the current approach to mitigation, and intended to capture the Commission's existing requirements. The Final Rule does not depart from this approach, and adopts the same regulatory text regarding mitigation as proposed in the NOPR, with the addition of a clarification that mitigation will apply only to the market or markets in which a seller is found, or presumed, to have market power.

5. Section 35.39 Affiliate Restrictions

1096. This section governs affiliate transactions and affiliate relationships and establishes certain conditions that a seller must satisfy as a condition of its market-based rate authority. New paragraph (a) explains that, as a condition of obtaining and retaining market-based rate authority, the provisions set forth in the entire section, including the restriction on affiliate sales of electric energy and the affiliate restrictions, must be satisfied on an ongoing basis. Paragraph (b) expressly prohibits sales between a franchised public utility with captive customers and any of its market-regulated power sales affiliates without first receiving authorization for the transaction under section 205 of the FPA. This paragraph requires that, where the Commission grants a seller authority to engage in affiliate sales under its MBR tariff, any and all such authorizations must be listed in the seller's tariff. The language varies from that proposed in the NOPR to reflect changes to the definition of ''franchised public utility.''

1097. Paragraphs (c)–(f) contain provisions governing the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliates (formerly, code of conduct). The provisions of these paragraphs apply to all franchised public utilities with captive customers. These paragraphs include provisions governing the separation of employees, the sharing of market information, sales of non-power goods or services, and power brokering. The language varies from that proposed in the NOPR to reflect changes to the definition of ''franchised public utility'' and a number of other changes discussed in greater detail in the affiliate abuse section of this Final Rule.

1098. As discussed above in Affiliate Abuse, the Commission is adding several provisions concerning separation of functions and information sharing to more closely model the Commission's standards of conduct, as appropriate. In addition, the final regulations include a new paragraph (g) with a general prohibition on using anyone as a conduit to circumvent any of the affiliate restrictions, and a new paragraph (h) explaining that, if necessary, affiliate restrictions involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not, will be imposed on a case-by-case basis.

6. Section 35.40 Ancillary Services

1099. This provision restricts sales of ancillary services to those specific geographic markets for which the Commission has authorized market-based rate sales of such services. In the Final Rule, we delete proposed paragraph (b), which reflected the Internet posting and reporting requirements found in *Avista Corporation*,[1220] and which we find are no longer necessary, as discussed above in the section on Ancillary Services. We also delete proposed subsection (c), which described limitations on sales of ancillary services by third-party providers; we believe that the standard applicable tariff provision, which will be available on the Commission's Web site as it may be revised from time to time, will adequately apprise sellers of the current policy concerning third-party providers.

7. Section 35.41 Market Behavior Rules

1100. In Order No. 674, the Commission rescinded two of its market behavior rules and codified the remainder in § 35.37 of new Subpart H. The NOPR proposed to move these market behavior rules, unchanged, from § 35.37 to § 35.41. NASUCA submitted a number of substantive comments on these provisions. Because we did not propose any revisions to these rules, and we are not revising them substantively in this Final Rule, NASUCA's comments are beyond the scope of this proceeding. We are, however, taking this opportunity to make several minor corrections and stylistic edits to the market behavior rules.

8. Section 35.42 Change in Status Reporting Requirement

1101. This section incorporates the provision previously found at paragraph 35.27(c), which was codified by Order No. 652. The final regulatory text clarifies distinctions between generation facilities and transmission facilities, and incorporates minor revisions as discussed above in the section on Changes in Status.

1102. The Final Rule adds paragraph (c), which codifies the requirement that each seller include an appendix identifying specified assets with each pertinent change in status notification filed. The paragraph also directs readers to Appendix B for a sample asset appendix.

9. Miscellaneous

1103. The final regulations add the phrase ''unless otherwise permitted by Commission rule or order'' in several places throughout the regulations to make clear that these general provisions are not meant to override approvals granted in particular circumstances in other orders or rules.

1104. In this Final Rule, the Commission has deleted proposed § 35.42, MBR Tariff, which required sellers to have on file the MBR tariff of general applicability. That requirement has been modified, as explained above in the section on the MBR tariff; accordingly the regulation will not be adopted.

VI. Information Collection Statement

1105. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[1221] Upon approval of a collection of information and data retention, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. As discussed herein, the Commission is amending its regulations to codify its requirements for obtaining and retaining market-based rate authorization, implementing a market-based rate tariff, and incorporating the change in status reporting requirement for sellers seeking market-based rate authority.

Initial Market Power Analysis

1106. The Commission has previously required utilities seeking market-based

[1220] *Avista Corporation*, 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61,136 (1999).

[1221] 5 CFR 1320.11.

rate authority to file a market power analysis with the Commission; the Commission now codifies that requirement in the Commission's regulations. This Final Rule reflects the Commission's existing practice developed over the years through individual cases and will not impose any additional burden, with the following exception.

1107. Section 35.27(a) of the Commission's regulations [1222] currently provides that any public utility seeking market-based rate authority shall not be required to submit a generation market power analysis with respect to sales from capacity for which construction commenced on or after July 9, 1996. Under current procedures, if all the generation owned or controlled by an applicant for market-based rate authority and its affiliates in the relevant balancing authority area is post-July 9, 1996 generation, such seller is not required to submit a generation market power analysis. In this Final Rule, the Commission eliminates the express exemption provided in § 35.27(a). This change means that all new sellers seeking market-based rate authority on or after the effective date of the Final Rule issued in this proceeding, whether or not all of their and their affiliates' generation was built or acquired after July 9, 1996, must provide a market power analysis of their generation to support their application for market-based rate authority.

1108. Because the Commission allows a seller to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any burden of document preparation occasioned by the elimination of § 35.27(a) should be minimal. To the extent that there are greater costs for some sellers, the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs.

Updated Market Power Analyses

1109. To retain market-based rate authority, the Commission currently requires that sellers file an updated market power analysis every three years. In this Final Rule, the Commission codifies the requirement that certain sellers with market-based rate authority file an updated analysis with the Commission to retain that authority. However, Category 1 sellers will be relieved of their existing obligation to file regularly scheduled updated market power analyses, as explained in the Implementation Process section of this Final Rule. Instead, sellers that believe they fall into Category 1 will be required to submit a filing with the Commission at the time that updated market power analyses for the seller's relevant market would otherwise be due (based on the regional schedule for updated market power analyses adopted in this Final Rule) explaining why the seller meets the Category 1 criteria, including a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area. Once the Commission agrees that a seller meets the Category 1 criteria, that seller will not have to file regularly scheduled updated market power analyses. Category 2 sellers will retain their existing obligation to file a regularly scheduled updated market power analysis. Thus, Category 2 sellers will not face a greater burden to provide the Commission with the information required for an updated market power analysis.

1110. In addition, the elimination of § 35.27(a) also means that existing Category 2 sellers filing updated market power analyses on or after the effective date of the Final Rule issued in this proceeding, whether or not all of their and their affiliates' generation was built or acquired after July 9, 1996, must provide a market power analysis of their generation to support their continued market-based rate authority.

1111. Mirant argues that, with the elimination of the § 35.27(a) exemption, its cost of compliance will increase because it will have to prepare four updated market power analyses, each costing $20,000 to prepare and file, for companies that would have qualified for the § 35.27(a) exemption. Mirant states that only one of its subsidiaries would qualify as a Category 1 seller and Mirant still would have to make four updated market power analysis filings. On the other hand, other commenters state that the benefits of eliminating the § 35.27(a) exemption outweigh any added burdens.

1112. Because the Commission allows a seller to make simplifying assumptions and rely on previously filed analyses by other market participants, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any burden of document preparation occasioned by the elimination of § 35.27(a) should be minimal. To the extent that there are greater costs for some sellers, the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs.

Regional Review and Schedule

1113. In the NOPR, the Commission proposed to require each seller to file an updated market power analysis for its relevant geographic market(s) on a schedule that will allow examination of the individual seller at the same time the Commission examines other sellers in these relevant markets and contiguous markets within a region from which power could be imported. The regional reviews would rotate by geographic region.

1114. Some commenters expressed concern that regional review would increase the burden associated with filing updated market power analyses. Reliant, for example, states that companies which engage in business in multiple regions of the United States would have to file several times over the three year schedule instead of once as is required currently.[1223] Other commenters support the regional review proposal. For example, NRECA maintains that the proposed regional approach will not impose an undue compliance burden on sellers. It notes that the regional review approach will ensure greater consistency in the data used to evaluate Category 2 sellers, citing the Commission's statement in the NOPR that the Commission ''will have before it a complete picture of the uncommitted capacity and simultaneous import capability into the relevant geographic markets under review.'' [1224] NRECA states that any increase in the burden on sellers hardly outweighs these substantial benefits. NRECA submits that the Commission has proposed a reasonable procedure to better ensure that market-based rate authority is granted only in appropriate circumstances. When compared with the burden, cost and time required by a cost-of-service rate regime, NRECA asserts that the burden of complying with the regional review approach will be minimal. APPA/TAPS describe the regional review proposed in the NOPR as a sensible proposal to conduct updated market power analyses on a rotating, regional basis to improve the quality and quantity of the data relied upon for market-based rate determinations and to provide the Commission with a more comprehensive picture of competitive conditions in regional markets. They assert that the Commission should not

[1222] 18 CFR 35.27(a).

[1223] Similarly, Allegheny, Mirant, FP&L, EEI, FirstEnergy, MidAmerican, TXU, Morgan Stanley, Financial Companies, and EPSA argue that large corporate families could find themselves in a perpetual triennial review that would place a substantial regulatory burden and expense on them.

[1224] NRECA reply comments at 28, citing NOPR at P 154.

sacrifice improvements to its market-based rate program to the interests of a few companies and that any increased financial cost to companies associated with regional reviews is outweighed by the companies' profits from market-based rate sales.

1115. We believe that the Commission's proposal properly and fairly balances the need to effectively, comprehensively, and accurately assess market power in wholesale markets with the desire to minimize any administrative burden associated with the filing and review of updated market power analyses. While we recognize that some sellers may file updates more frequently than currently, we have carefully balanced the interests of all involved, and we believe that regional reviews of updated market analyses will result in more accurate and complete data. This in turn will enhance the Commission's ability to continue to ensure that sellers either lack market power or have adequately mitigated such market power.

1116. Further, in light of commenters' concern with the regional review schedule, the Commission has modified the schedule as proposed in the NOPR. The NOPR proposed that regional reviews would rotate by geographic region with three regions reviewed per year. Some commenters expressed concerned that, because they operate in multiple regions, they would be required to file updated market power analyses every year rather than every three years. To address this concern, we are reducing the number of filings that sellers with generation in multiple regions will have to make by consolidating the regions and reducing the total number from nine to six. With fewer and larger regions, sellers will likely occupy fewer regions, necessitating fewer filings.

Market-Based Rate Tariff

1117. The NOPR proposed a tariff of general applicability (MBR tariff), which would provide greater consistency and reduce confusion regarding tariffs. The Commission recognized that the requirement to file the specified MBR tariff might cause a minimal burden of document preparation and organization for existing market-based rate sellers, but stated that long-term benefits would be realized for market participants as well as the Commission.

1118. In this Final Rule, we do not adopt the NOPR proposal to require all sellers to adopt a tariff of general applicability. Instead, we adopt a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff. While we will require all market-based rate sellers to make compliance filings to modify their existing tariffs to reflect these standard provisions, these compliance filings are to be made by each seller the next time the seller proposes a tariff change, makes a change in status filing, or submits an updated market power analysis in accordance with the schedule in Appendix D, whichever occurs first.

1119. In the NOPR, the Commission also proposed that all market-based rate sellers file one market-based rate tariff per corporate family. Many commenters expressed concern with this proposal. In light of these concerns, we are not requiring sellers to file one market-based rate tariff per corporate family. Instead, we will allow sellers to elect whether to transact under a single market-based rate tariff for an entire corporate family or under separate tariffs.

General

1120. The Commission's regulations in 18 CFR Part 35 specify those reporting requirements that must be followed in conjunction with the filing of rate schedules under the FPA. The information provided to the Commission under 18 CFR Part 35 is identified for information collection and records retention purposes as FERC–516. Data collection FERC–516 applies to all reporting requirements covered in 18 CFR Part 35 including: electric rate schedule filings, market power analyses, tariff submissions, market-based rate analyses, and reporting requirements for changes in status for public utilities with market-based rate authority.

1121. The Commission is submitting these reporting and records retention requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[1225] The Commission solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission did not receive comments specifically addressing the burden estimates in the NOPR. With the exceptions of estimates regarding sellers' market-based rate tariffs, the number of market-based rate sellers, and the burden estimates for Category 1 sellers, we will use the same estimates here as in the NOPR.[1226]

1122. The number of respondents expected to file to revise market-based rate tariffs has increased from the estimate set forth in the NOPR, given our decision not to require one MBR tariff per corporate family. We expect some sellers will opt to submit a single corporate tariff, but we will estimate the total number to be filed to be approximately 1230, rather than 650 as reported in the NOPR. We will conform the number of responses to reflect this new estimate as well. However, we note that this number may be significantly less if sellers choose the option to file one market-based rate tariff per corporate family. Additionally, the Commission proposed in the NOPR that sellers file their MBR tariffs as directed in the rulemaking proceeding requiring the submission of electronic tariffs. However, in this Final Rule, we are requiring that sellers file their modified tariffs the next time sellers propose a tariff change, make a change in status filing, or submit an updated market power analysis. We have adjusted the number of responses to reflect this requirement.

Burden Estimate: The Public Reporting and records retention burden for all four reporting requirements and the records retention requirement is as follows.[1227]

[1225] 44 U.S.C. 3507(d).

[1226] We note that the number of market-based rate sellers has increased since issuance of the NOPR in May 2006.

[1227] These burden estimates apply only to this Final Rule and do not reflect upon all of FERC–516.

Title: Electric Rate Schedule Filings (FERC–516).

OMB Control No: 1902–0096.

Action: Revised Collection.

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Initial Market Power Analysis	120	120	130	15,600
Market-Based Rate Tariff	1230	[1228] 410	6	2,460
Category 1 Qualification Filings [1229]	630	[1230] 210	15 [1231]	3,150
Updated Analyses	600	[1233] 200	250	50,000
Category 2 [1232] Totals				71,210

Total Annual Hours for Collection: (Reporting + record retention (if appropriate) = 71,210 hours.

Information Collection Costs: The total annual cost for Initial Market Power Analyses is estimated to be $2,340,000. Total annual cost for market-based rate tariffs is projected to be $369,000 for the first year. Total annual cost for Category 1 Qualification Filings is projected to be $472,500.[1234] Total annual cost for Updated Market Power Analyses Category 2 is projected to be $7,500,000. The hourly rate of $150 includes attorney fees, engineering consultation fees and administrative support. There are 2080 total work hours in a year. There are no filing fees associated with applications for market-based rate authority.

Respondents (Market Power Analysis; MBR Tariff; Triennial Review): Businesses or other for profit.

Frequency of Responses

Market Power Analyses: Occasionally; consistent with current practice, a market power analysis must be filed for each utility seeking market-based rate authority.

Market-Based Rate Tariffs: Once, consistent with the requirement that all sellers file modifications to their existing tariffs in accordance with the provisions in Appendix C.

Updated Market Power Analyses: Updated market power analysis filed every three years for Category 2 sellers seeking to retain market-based rate authority.

Necessity of the Information

Market Power Analyses: Consistent with current practice, the market power analysis helps inform the Commission as to whether an entity seeking market-based rate authority lacks market power, and whether sales by that entity will be just and reasonable.

Market-Based Rate Tariff: Market-based rate tariffs with standard provisions will improve the efficiency of the Commission in its analysis and determination of market-based rate authority. These will reduce document preparation time overall and provide utilities with the clearly defined expectations of the Commission.

Updated Market Power Analyses: The updated market power analyses allow the Commission to monitor market-based rate authority to detect changes in market power or potential abuses of market power. The updated market power analysis permits the Commission to determine that continued market-based rate authority will still yield rates that are just and reasonable.

Internal review: The Commission has conducted an internal review of the public reporting burden associated with the collection of information and assured itself, by means of internal review, that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collections of information and has determined that these collections of information are necessary and conform to the Commission's plans, as described in this order, for the collection, efficient management, and use of the required information.[1235]

1123. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov* or the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

VII. Environmental Analysis

1124. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[1236] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to electric rate filings.[1237]

VIII. Regulatory Flexibility Act

1125. The Regulatory Flexibility Act of 1980 (RFA) [1238] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities.[1239] The Final Rule will be

[1228] We expect responses to be staggered over the course of three years. Accordingly, the number of respondents (1230) has been divided by 3.

[1229] Category 1 sellers are power marketers and power producers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory. In addition, Category 1 sellers must not own, operate or control transmission facilities, and must present no other vertical market power issues. There are approximately 630 Category 1 sellers.

[1230] To determine the number of responses, the number of respondents (630) has been divided by 3 because the Category 1 filings will be submitted to the Commission on a staggered basis over the course of a three-year period. After the first three years, the number of responses will be zero.

[1231] This estimate reflects the limited scope of the filing required by Category 1 sellers, *i.e.*, a filing explaining why the seller meets the Category 1 criteria and including a list of all generation assets owned or controlled by the seller and its affiliates grouped by balancing authority area.

[1232] Category 2 sellers are any sellers not in Category 1.

[1233] To determine the number of responses, the number of respondents (600) has been divided by 3 because the responses will be submitted to the Commission on a staggered basis over the course of a three year period.

[1234] We note that Category 1 sellers will only be required to file on a single occasion Category 1 qualification filings whereas Category 2 sellers will file updated market power analyses every three years.

[1235] *See* 44 U.S.C. 3506(c).

[1236] Order No. 486, *Regulations Implementing the National Environmental Policy Act,* 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[1237] 18 CFR 380.4(a)(15).

[1238] 5 U.S.C. 601–12.

[1239] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act,

Continued

applicable to all public utilities seeking and currently possessing market-based rate authority. The Commission finds that the regulations adopted here should not have a significant impact on small businesses.

1126. The submission of a market power analysis is currently required of all entities seeking authority to sell at market-based rates, and the Final Rule does not expand which entities will be required to file these analyses. The Final Rule does not create a new reporting requirement. It does, however, expand the scope of the analysis that must be submitted for those entities that previously were exempted from preparing a generation market power analysis by virtue of 18 CFR 35.27(a). The Commission is concerned that the continued use of the § 35.27(a) exemption, in time, would encompass all market participants as all pre-July 9, 1996 generation is retired. Nevertheless, because the Commission allows a seller to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any additional burden imposed by the elimination of the § 35.27(a) exemption will be minimal.

1127. Standard tariff provisions will decrease document preparation by clearly defining the information sought by the Commission.

1128. For certain sellers, the triennial review submissions that provide updated market power analyses are required for the retention of market-based rate authority. Category 2 utilities shall continue to submit this analysis, which poses no greater burden than that already in place. However, the regulations will result in fewer filings with the Commission after the next three years than currently required for qualified smaller (Category 1) utilities' retention of market-based rate authority. Thus, the Final Rule will be less burdensome economically and reduce the frequency of document preparation for market-based rate authority retention for qualified smaller utilities. The Commission concludes that this Final Rule will not have a significant economic impact on a substantial number of small entities.

which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. 15 U.S.C. 632. The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal year did not exceed 4 million MWh. 13 CFR 121.201 (section 22, Utilities, North American Industry Classification System, NAICS).

IX. Document Availability

1129. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

1130. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1131. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll-free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371 Press 0, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

X. Effective Date and Congressional Notification

1132. These regulations are effective September 18, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and to the General Accounting Office.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Moeller dissenting in part with a separate statement in Attachment A.

Kimberly D. Bose,

Secretary.

■ In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

■ 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. § 35.27 is revised to read as follows:

§ 35.27 Authority of State commissions.

Nothing in this part—

(a) 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

(b) Limits the authority of a State commission in accordance with State and Federal law to establish

(1) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(2) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with State law.

■ 3. Subpart H is revised to read as follows:

Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

Sec.
35.36 Generally.
35.37 Market power analysis required.
35.38 Mitigation.
35.39 Affiliate restrictions.
35.40 Ancillary services.
35.41 Market behavior rules.
35.42 Change in status reporting requirement.
Appendix A to Subpart H Standard Screen Format
Appendix B to Subpart H Corporate Entities and Assets

Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

§ 35.36 Generally.

(a) For purposes of this subpart:

(1) *Seller* means any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the Federal Power Act.

(2) *Category 1 Sellers* means wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.

(3) *Category 2 Sellers* means any Sellers not in Category 1.

(4) *Inputs to electric power production* means intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; sources of coal supplies and equipment for the transportation of coal supplies such as barges and rail cars.

(5) *Franchised public utility* means a public utility with a franchised service obligation under State law.

(6) *Captive customers* means any wholesale or retail electric energy customers served under cost-based regulation.

(7) *Market-regulated power sales affiliate* means any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part on a market-rate basis.

(8) *Market information* means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.

(b) The provisions of this subpart apply to all Sellers authorized, or seeking authorization, to make sales for resale of electric energy, capacity or ancillary services at market-based rates unless otherwise ordered by the Commission.

§ 35.37 Market power analysis required.

(a) (1) In addition to other requirements in subparts A and B, a Seller must submit a market power analysis in the following circumstances: when seeking market-based rate authority; for Category 2 Sellers, every three years, according to the schedule contained in Order No. 697, FERC Stats. & Regs. ¶ 31,252; or any other time the Commission directs a Seller to submit one. Failure to timely file an updated market power analysis will constitute a violation of Seller's market-based rate tariff.

(2) When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets in the form provided in Appendix B of this subpart.

(b) A market power analysis must address whether a Seller has horizontal and vertical market power.

(c) (1) There will be a rebuttable presumption that a Seller lacks horizontal market power if it passes two indicative market power screens: a pivotal supplier analysis based on the annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a Seller possesses horizontal market power if it fails either screen.

(2) Sellers and intervenors may also file alternative evidence to support or rebut the results of the indicative screens. Sellers may file such evidence at the time they file their indicative screens. Intervenors may file such evidence in response to a Seller's submissions.

(3) If a Seller does not pass one or both screens, the Seller may rebut a presumption of horizontal market power by submitting a Delivered Price Test analysis. A Seller that does not rebut a presumption of horizontal market power or that concedes market power, is subject to mitigation, as described in § 35.38.

(4) When submitting a horizontal market power analysis, a Seller must use the form provided in Appendix A of this subpart and include all supporting materials referenced in the form.

(d) To demonstrate a lack of vertical market power, a Seller that owns, operates or controls transmission facilities, or whose affiliates own, operate or control transmission facilities, must have on file with the Commission an Open Access Transmission Tariff, as described in § 35.28; provided, however, that a Seller whose foreign affiliate(s) own, operate or control transmission facilities outside of the United States that can be used by competitors of the Seller to reach United States markets must demonstrate that such affiliate either has adopted and is implementing an Open Access Transmission Tariff as described in § 35.28, or otherwise offers comparable, non-discriminatory access to such transmission facilities.

(e) To demonstrate a lack of vertical market power in wholesale energy markets through the affiliation, ownership or control of inputs to electric power production, such as the transportation or distribution of the inputs to electric power production, a Seller must provide the following information:

(1) A description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities;

(2) Sites for generation capacity development; and

(3) Sources of coal supplies and the transportation of coal supplies such as barges and rail cars.

(4) A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

(f) If the seller seeks to protect any portion of the application, or any attachment thereto, from public disclosure pursuant to § 388.112 of this chapter, the seller must include with its request for privileged treatment a proposed protective order under which the parties to the proceeding will be able to review any of the data, information, analysis or other documentation relied upon by the seller for which privileged treatment is sought. A seller must grant access to privileged data to any party that signs a protective order within 5 days from the date that the party executes the protective order.

§ 35.38 Mitigation.

(a) A Seller that has been found to have market power in generation or that is presumed to have horizontal market power by virtue of failing or foregoing the horizontal market power screens, as described in § 35.37(c), may adopt the default mitigation detailed in paragraph (b) of this section or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power. Mitigation will apply only to the market(s) in which the Seller is found, or presumed, to have market power.

(b) Default mitigation consists of three distinct products:

(1) Sales of power of one week or less priced at the Seller's incremental cost plus a 10 percent adder;

(2) Sales of power of more than one week but less than one year priced at no higher than a cost-based ceiling reflecting the costs of the unit(s) expected to provide the service; and

(3) New contracts filed for review under section 205 of the Federal Power Act for sales of power for one year or more priced at a rate not to exceed embedded cost of service.

§ 35.39 Affiliate restrictions.

(a) *General affiliate provisions.* As a condition of obtaining and retaining market-based rate authority, the conditions provided in this section, including the restriction on affiliate sales of electric energy and all other

affiliate provisions, must be satisfied on an ongoing basis, unless otherwise authorized by Commission rule or order. Failure to satisfy these conditions will constitute a violation of the Seller's market-based rate tariff.

(b) *Restriction on affiliate sales of electric energy.* As a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act. All authorizations to engage in affiliate wholesale sales of electric energy must be listed in a Seller's market-based rate tariff.

(c) *Separation of functions.* (1) For the purpose of this paragraph, entities acting on behalf of and for the benefit of a franchised public utility with captive customers (such as entities controlling or marketing power from the electrical generation assets of the franchised public utility) are considered part of the franchised public utility. Entities acting on behalf of and for the benefit of the market-regulated power sales affiliates of a franchised public utility with captive customers are considered part of the market-regulated power sales affiliates.

(2) (i) To the maximum extent practical, the employees of a market-regulated power sales affiliate must operate separately from the employees of any affiliated franchised public utility with captive customers.

(ii) Franchised public utilities with captive customers are permitted to share support employees, and field and maintenance employees with their market-regulated power sales affiliates. Franchised public utilities with captive customers are also permitted to share senior officers and boards of directors with their market-regulated power sales affiliates; provided, however, that the shared officers and boards of directors must not participate in directing, organizing or executing generation or market functions.

(iii) Notwithstanding any other restrictions in this section, in emergency circumstances affecting system reliability, a market-regulated power sales affiliate and a franchised public utility with captive customers may take steps necessary to keep the bulk power system in operation. A franchised public utility with captive customers or the market-regulated power sales affiliate must report to the Commission and disclose to the public on its Web site, each emergency that resulted in any deviation from the restrictions of section 35.39, within 24 hours of such deviation.

(d) *Information sharing.* (1) Unless simultaneously disclosed to the public, market information may not be shared between a franchised public utility with captive customers and a market-regulated power sales affiliate if the sharing could be used to the detriment of captive customers.

(2) Permissibly shared support employees, field and maintenance employees and senior officers and board of directors under §§ 35.39(c)(2)(ii) may have access to information covered by the prohibition of § 35.39(d)(1), subject to the no-conduit provision in § 35.39(g).

(e) *Non-power goods or services.* (1) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a franchised public utility with captive customers, to a market-regulated power sales affiliate must be at the higher of cost or market price.

(2) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers may not be at a price above market.

(f) *Brokering of power.* (1) Unless otherwise permitted by Commission rule or order, to the extent a market-regulated power sales affiliate seeks to broker power for an affiliated franchised public utility with captive customers:

(i) The market-regulated power sales affiliate must offer the franchised public utility's power first;

(ii) The arrangement between the market-regulated power sales affiliate and the franchised public utility must be non-exclusive; and

(iii) The market-regulated power sales affiliate may not accept any fees in conjunction with any brokering services it performs for an affiliated franchised public utility.

(2) Unless otherwise permitted by Commission rule or order, to the extent a franchised public utility with captive customers seeks to broker power for a market-regulated power sales affiliate:

(i) The franchised public utility must charge the higher of its costs for the service or the market price for such services;

(ii) The franchised public utility must market its own power first, and simultaneously make public (on the Internet) any market information shared with its affiliate during the brokering; and

(iii) The franchised public utility must post on the Internet the actual brokering charges imposed.

(g) *No conduit provision.* A franchised public utility with captive customers and a market-regulated power sales affiliate are prohibited from using anyone, including asset managers, as a conduit to circumvent the affiliate restrictions in §§ 35.39(a) through (g).

(h) *Franchised utilities without captive customers.* If necessary, any affiliate restrictions regarding separation of functions, power sales or non-power goods and services transactions, or brokering involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not have captive customers, will be imposed on a case-by-case basis.

§ 35.40 Ancillary services.

A Seller may make sales of ancillary services at market-based rates only if it has been authorized by the Commission and only in specific geographic markets as the Commission has authorized.

§ 35.41 Market behavior rules.

(a) *Unit operation.* Where a Seller participates in a Commission-approved organized market, Seller must operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission-approved rules and regulations of the applicable market. A Seller is not required to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or is a requirement applicable to Seller through Seller's participation in a Commission-approved organized market.

(b) *Communications.* A Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.

(c) *Price reporting.* To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the Policy

Statement issued by the Commission in Docket No. PL03–3–000 and any clarifications thereto. Unless Seller has previously provided the Commission with a notification of its price reporting status, Seller must notify the Commission within 15 days of the effective date of this regulation or within 15 days of the date it begins making wholesale sales, whichever is earlier, whether it engages in such reporting of its transactions. Seller must update the notification within 15 days of any subsequent change in its transaction reporting status. In addition, Seller must adhere to such other standards and requirements for price reporting as the Commission may order.

(d) *Records retention.* A Seller must retain, for a period of five years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to Seller's market-based rate tariff, and the prices it reported for use in price indices.

§ 35.42 Change in status reporting requirement.

(a) As a condition of obtaining and retaining market-based rate authority, a Seller must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. A change in status includes, but is not limited to, the following:

(1) Ownership or control of generation capacity that results in net increases of 100 MW or more, or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

(2) Affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation facilities or inputs to electric power production, affiliation with any entity not disclosed in the application for market-based rate authority that owns, operates or controls transmission facilities, or affiliation with any entity that has a franchised service area.

(b) Any change in status subject to paragraph (a) of this section must be filed no later than 30 days after the change in status occurs. Power sales contracts with future delivery are reportable 30 days after the physical delivery has begun. Failure to timely file a change in status report constitutes a tariff violation.

(c) When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of assets in the form provided in Appendix B of this subpart.

Appendix A to Subpart H

STANDARD SCREEN FORMAT

[Data provided for Illustrative Purposes only]

Row	Generation	MW	Reference
	Part I—Pivotal Supplier Analysis		
	Seller and Affiliate Capacity		
A	Installed Capacity	19,500	Workpaper.
B	Long-Term Firm Purchases	500	Workpaper.
C	Long-Term Firm Sales	−1,000	Workpaper.
D	Imported Power	0	Workpaper.
	Non-Affiliate Capacity		
E	Installed Capacity	8,000	Workpaper.
F	Long-Term Firm Purchases	500	Workpaper.
G	Long-Term Firm Sales	−2,500	Workpaper.
H	Imported Power	3,500	Workpaper.
I	Balancing Authority Area Reserve Requirement	−2,160	Workpaper.
J	Amount of Line I Attributable to Seller, if any	−2,160	Workpaper.
K	Total Uncommitted Supply (SUM A,B,C,D,E,F,G,I)	9,840	
	Load		
L	Balancing Authority Area Annual Peak Load	18,000	Workpaper.
M	Average Daily Peak Native Load in Peak Month	−16,500	Workpaper.
N	Amount of Line M Attributable to Seller, if any	−16,500	Workpaper.
O	Wholesale Load (SUM L,M)	1,500	
P	Net Uncommitted Supply (K–O)	8,340	
Q	Seller's Uncommitted Capacity (SUM A,B,C,D,J,N)	340	
Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		PASS	

Row		Q1 (MW)	Q2 (MW)	Q3 (MW)	Q4 (MW)	Reference
	Part II—Market Share Analysis					
	Seller and Affiliate Capacity					
A	Installed Capacity	19,500	19,500	19,500	19,500	Workpaper.
B	Long-Term Firm Purchases	500	500	500	500	Workpaper.
C	Long-Term Firm Sales	−1,000	−1,000	−1,000	−1,000	Workpaper.
D	Seasonal Average Planned Outages	−4,000	−3,000	−800	−3,500	Workpaper.
E	Imported Power	0	0	0	0	Workpaper.
	Capacity Deductions					
F	Average Peak Native Load in the Season	−11,500	−10,000	−12,500	−11,500	Workpaper.
G	Amount of Line F Attributable to Seller, if any	−11,500	−10,000	−12,500	−11,500	Workpaper.
H	Amount of Line F Attributable to Others, if any	0	0	0	0	Workpaper.
I	Balancing Authority Area Reserve Requirement	−1,500	−1,320	−1,560	−1,500	Workpaper.
J	Amount of Line I Attributable to Seller, if any	−1,500	−1,320	−1,560	−1,500	Workpaper.
K	Amount of Line I Attributable to Others, if any	0	0	0	0	Workpaper.
	Non-Affiliate Capacity					
L	Installed Capacity	8,000	8,000	8,000	8,000	Workpaper.
M	Long-Term Firm Purchases	500	500	500	500	Workpaper.
N	Long-Term Firm Sales	−2,500	−2,500	−2,500	−2,500	Workpaper.
O	Local Seasonal Average Planned Outages	−800	−200	−300	−400	Workpaper.
P	Uncommitted Capacity Imports	5,000	4,500	3,500	4,000	Workpaper.
	Supply Calculation					
Q	Total Competing Supply (SUM L,M,N,O,P,H,K)	10,200	10,300	9,200	9,600	
R	Seller's Uncommitted Capacity (SUM A,B,C,D,E,G,J)	2,000	4,680	4,140	2,500	
S	Total Seasonal Uncommitted Capacity (SUM Q,R)	12,200	14,980	13,340	12,100	
T	Seller's Market Share (R/S)	16.39%	31.24%	31.03%	20.66%	
	Results (Pass if < 20%) (Fail if ≥ 20%)	PASS	FAIL	FAIL	FAIL	

Appendix B to Subpart H

This is an example of the required appendix listing the filing entity and all its energy affiliates and their associated assets which should be submitted with all market-based rate filings.

MARKET-BASED RATE AUTHORITY AND GENERATION ASSETS

Filing entity and its energy affiliates	Docket No. where MBR authority was granted	Generation name	Owned by	Controlled by	Date control transferred	Location		In-service date	Nameplate and/or seasonal rating
						Balancing authority area	Geographic region (per Appendix D)		
ABC Corp.	ER05–23X–000	ABC falls plant #1	ABC Corp	ABC Corp	NA*	ABC balancing authority area.	Central	8/12/1981	153.5 MW (seasonal).
xyz Inc.	ER94–79XX–000	NA	NA	NA	NA	NA	NA	NA	NA.
RST LLC	ER01–2XX5–000	Green CoGen	WWW Corp	RST LLC	5/23/2005	New York ISO.	Northeast	12/20/2003	2000 MW (nameplate).
Sample Co.	ER03–XX45–000	Sample Co. 3	Sample Co	YYY Corp	2/1/1982	Sample Co. balancing authority.	Southwest	5/13/1973	10 MW (seasonal).

*If an entity has no assets or the field is not applicable please indicate so by inputting (NA).

ELECTRIC TRANSMISSION ASSETS AND/OR NATURAL GAS INTRASTATE PIPELINES AND/OR GAS STORAGE FACILITIES

Filing entity and its energy affiliates	Asset name and use	Owned by	Controlled by	Date control transferred	Location		Size
					Balancing authority area	Geographic region (per Appendix D)	
ABC Corp	CBA Line, used to interconnect Green Cogen to New York ISO transmission system.	ABC Corp	ABC Corp	NA*	New York ISO	Northeast	approximately five-mile, 500 kV line.
Etc. LP	Nowhere Pipeline, used to connect Storage LLC's—Longway Pipeline to ABC falls plant #1.	Etc. LP	Etc. LP	NA	ABC balancing authority area.	Central	approximately 14 miles of natural gas pipeline and related equipment with 50 MMcf/d capacity.

*If the field is not applicable please indicate so by inputting (NA).

Note: The following appendices will not be published in the Code of Federal Regulations.

Appendix C to the Final Rule

Required Provisions of the Market-Based Rate Tariff

Compliance With Commission Regulations

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

Limitations and Exemptions Regarding Market-Based Rate Authority

[Seller should list all limitations (including markets where seller does not have market-based rate authority) on its market-based rate authority and any exemptions from or waivers granted of Commission regulations and include relevant cites to Commission orders].

Include All of the Following Provisions That Are Applicable

Mitigated Sales

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area; (ii) any power sold hereunder is not intended to serve load in the seller's mitigated market; and (iii) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i), (ii) and (iii) above.

Ancillary Services

RTO/ISO Specific—Include All Services the Seller Is Offering

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. (''PJM'') and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral

sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation (''CAISO'') and to others that are self-supplying ancillary services to the CAISO.

Third Party Provider

Third-party ancillary services [include all of the following that the seller is offering: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves]. Sales will not include the following: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

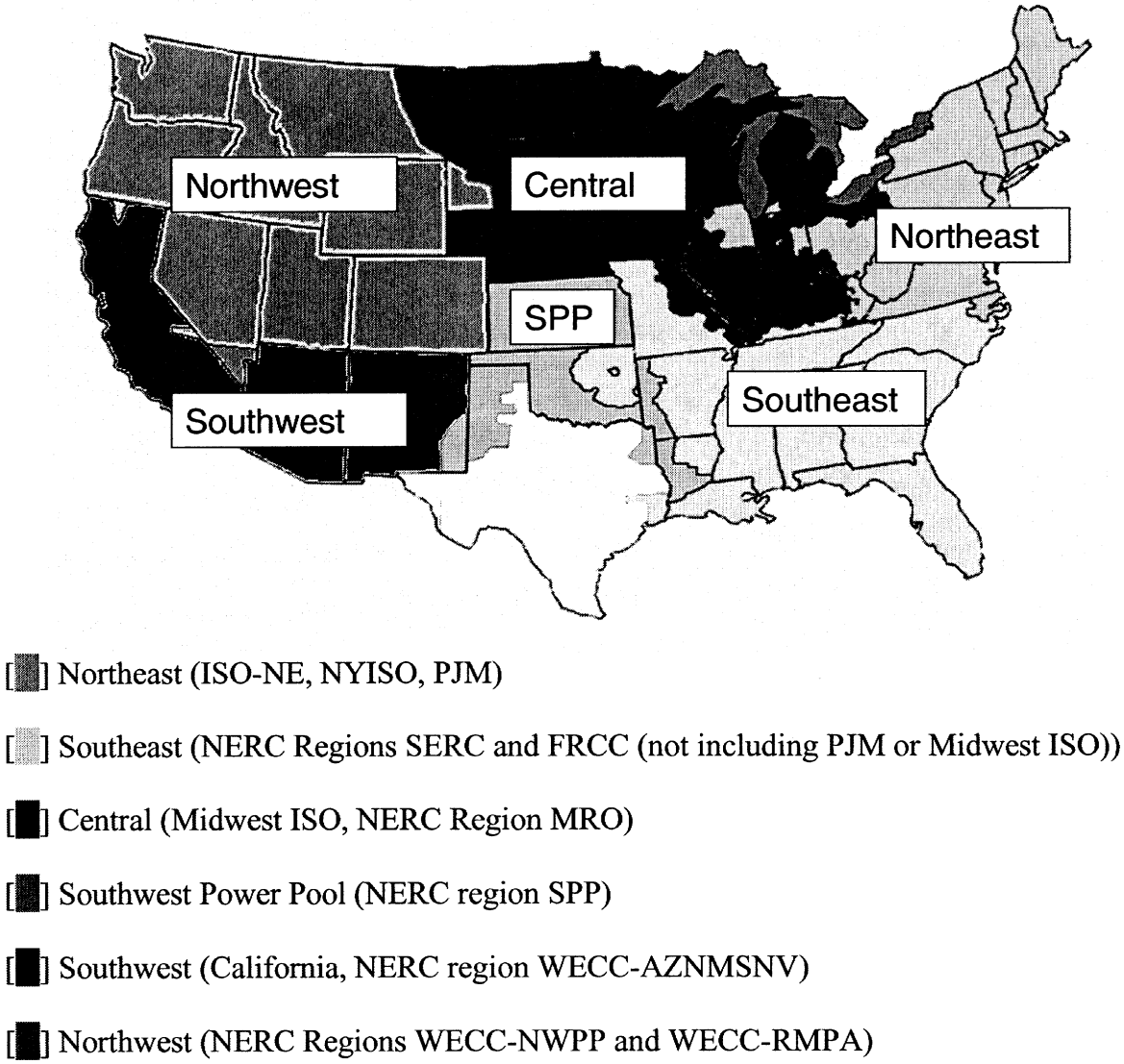
Appendix D to the Final Rule

Regions and Schedule for Regional Market Power Update Process

The six regions are combinations of NERC regions; RTOs and ISOs and are depicted in the map that follows.

BILLING CODE 6717–01–P

Map of Geographic Regions



BILLING CODE 6717–01–C

REGIONAL MARKET POWER UPDATE SCHEDULE

Study period	Filing period (anytime between)	Entities required to file	
2006	December 1–30, 2007	Northeast Transmission Operators.	
2006	June 1–30, 2008	Southeast Transmission Operators.	All others in Northeast that did not file in December including all power marketers that sold in the Northeast.
2006	December 1–30, 2008		All others in Southeast that did not file in June including all power marketers that sold in the Southeast and have not already been found to be Category 1 sellers.
2007	December 1–30, 2008	Central Transmission Operators.	
2007	June 1–30, 2009	SPP Transmission Operators	All others in Central that did not file in December including all power marketers that sold in the Central and have not already been found to be Category 1 sellers.
2007	December 1–30, 2009		All others in SPP that did not file in June including all power marketers that sold in SPP and have not already been found to be Category 1 sellers.
2008	December 1–30, 2009	Southwest Transmission Operators.	
2008	June 1–30, 2010	Northwest Transmission Operators.	All others in Southwest that did not file in December including all power marketers that sold in the Southwest and have not already been found to be Category 1 sellers.
2008	December 1–30, 2010		All others in Northwest that did not file in June including all power marketers that sold in the Northwest and have not already been found to be Category 1 sellers.
2009	December 1–30, 2010	Northeast Transmission Operators.	
All Category 1 sellers should be identified by the Commission prior to the subsequent filing periods. Only Category 2 sellers will continue to file updated market power analyses according to the repeating schedule below.			
2009	June 1–30, 2011	Southeast Transmission Operators.	Others in Northeast that did not file in December and have not been found to be Category 1 sellers.
2009	December 1–30, 2011		Others in Southeast that did not file in June and have not been found to be Category 1 sellers.
2010	December 1–30, 2011	Central Transmission Operators.	
2010	June 1–30, 2012	SPP Transmission Operators	Others in Central that did not file in December and have not been found to be Category 1 sellers.
2010	December 1–30, 2012		Others in SPP that did not file in June and have not been found to be Category 1 sellers.
2011	December 1–30, 2012	Southwest Transmission Operators.	
2011	June 1–30, 2013	Northwest Transmission Operators.	Others in Southwest that did not file in December and have not been found to be Category 1 sellers.
2011	December 1–30, 2013		Others in Northwest that did not file in June and have not been found to be Category 1 sellers.

This review cycle will be repeated in subsequent years.

Appendix E to the Final Rule

List of Commenters and Acronyms

Allegheny Energy Supply Co. and Allegheny Power—Allegheny Energy Companies
Alliance for Cooperative Energy Services Power Marketing LLC—Alliance Power Marketing
Ameren Services Co., Inc.—Ameren
AARP—AARP
American Public Power Association/Transmission Access Policy Study Group—APPA/TPAS
American Wind Energy Association—AWEA
Avista Corp.—Avista
Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia—Dalton Utilities
California Electricity Oversight Board—California Board
California Independent System Operator Corp.—CAISO
California Public Utilities Commission—California Commission
Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition, Industrial Energy Users of Ohio, Southeast Electricity Consumers Association, Southwest Industrial Customer Coalition—Industrial Customers
Cogentrix Energy, Inc. and Goldman Sachs Group—Cogentrix/Goldman
Constellation Energy Group, Inc.—Constellation
Consumers Energy Co.—Consumers
Dominion Resources Services, Inc.—Dominion
Duke Energy Corp.—Duke
Duquesne Power, LLC; Duquesne Light Company; Duquesne Keystone, LLC; Duquesne Conemaugh, LLC; and Monmouth Energy, Inc.—Duquesne Companies
E.ON U.S. LLC—E.ON U.S.
Edison Electric Institute—EEI
ElectriCities of North Carolina, Inc. and Piedmont Municipal Power Agency—Carolina Agencies
Electricity Consumers Resource Council—ELCON
El Paso E&P Co. L.P.—El Paso E&P
Electric Power Supply Association—EPSA
Entergy Services, Inc.—Entergy
FirstEnergy Service Co.—FirstEnergy
Florida Power & Light Company and FPL Energy, LLC—FP&L
Indianapolis Power & Light Co.—Indianapolis P&L
ISO New England Inc.—ISO–NE
Joe Pace, PhD—Dr. Pace
Mark B. Lively—Mr. Lively

Merrill Lynch Commodities Inc., J.P. Morgan Ventures Energy Corp. and Bear Energy—Financial Companies
MidAmerican Energy Co. and PacifiCorp—MidAmerican
Midwest Energy, Inc.—Midwest Energy
Mirant Corp.—Mirant
Montana Consumer Counsel—Montana Counsel
Morgan Stanley Capital Group Inc.—Morgan Stanley
National Association of State Utility Consumer Advocates—NASUCA
National Rural Electric Cooperative Association—NRECA
New Jersey Board of Public Utilities—New Jersey Board
New Mexico Office of Attorney General, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Public Citizen, Public Utility Law Project of New York, Rhode Island Office of Attorney General, and Rhode Island Division of Public Utilities and Carriers—State AGs and Advocates
New York Independent System Operator, Inc.—NYISO
New York State Public Service Commission—New York Commission
Newfoundland and Labrador Hydro—NL Hydro
Newmont Mining Corp.—Newmont
NiSource Inc.—NiSource
NRG Energy, Inc.—NRG
Oregon Public Utilities Commission—Oregon Commission
Ormet Power Marketing—Ormet
Pacific Gas & Electric Co.—PG&E
Piedmont Municipal Power Agency and ElectriCities of North Carolina—Carolina Agencies
Pinnacle West Companies—Pinnacle
Powerex Corp.—Powerex
PPL Companies—PPL
PPM Energy, Inc.—PPM
Progress Energy, Inc.—Progress Energy
Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC—PSEG Companies
Public Service Co. of New Mexico/Tuscon Electric Power Company—PNM/Tuscon
Public Works Commission for the City of Fayetteville, North Carolina—Fayetteville
Puget Sound Energy, Inc.—Puget
Reliant Energy, Inc.—Reliant
Richard Blumenthal, Attorney General for the State of Connecticut and the People of the State of Illinois, by and through the Illinois Attorney General, Lisa Madigan—Attorneys General of Connecticut and Illinois
Romkaew Broehm, PhD. and Peter Fox-Penner—Drs. Broehm and Fox-Penner
Sempra Energy—Sempra
Southern California Edison Co.—SoCal Edison
Southern Company Services, Inc.—Southern
Southwest Industrial Customer Coalition—Southwest Coalition
Suez Energy North America, Inc. and Chevron USA Inc.—Suez/Chevron
Towns of Black Creek, NC; Dallas, NC; Forest City, NC; Lucama, NC; Sharpsburg, NC; Stantonsburg, NC; and Waynesville, NC—NC Towns
Transmission Dependent Utility Systems—TDU Systems
TXU Portfolio Management Co. LP—TXU Wholesale
Westar Energy, Inc. and Kansas Gas and Electric Co.—Westar
Williams Power Co., Inc.—Williams
Wisconsin Electric Power Co.—Wisconsin Electric
Xcel Energy Services Inc.—Xcel

Note: The following attachment will not appear in the Code of Federal Regulations

Attachment A to the Final Rule

MOELLER, Commissioner, dissenting in part: I find persuasive the arguments raised by commenters [1240] that a limited grandfathering provision for the ''1996 exemption'' [1241] is warranted, to avoid modifying the understanding that certain generators relied upon to finance and construct new generation. It is my position that, with respect to sales from capacity for which construction commenced on or after July 9, 1996, but before the effective date of this Final Rule, any public utility that has authority to engage in market-based rate sales should not be required to demonstrate a lack of market power in generation consistent with the terms of the exemption. That is, any public utility that qualified and received a 1996 exemption should retain its exemption from filing a generation market power analysis (now termed horizontal market power analysis). However, any increase in such capacity after the effective date of this Final Rule would terminate the exemption.

As I have stated previously, I am interested in providing regulatory certainty, and promoting infrastructure investment and independent power production. A limited grandfathering of the 1996 exemption would, on one hand, allow entities to continue to preserve the bargain they received when they relied on the exemption and, on the other hand, support the majority's reasons for revoking the exemption for all generators.

Also, my understanding is that very few entities would be eligible for this limited grandfathering; even without the grandfathering, they would probably be classified as ''Category 1 sellers.'' [1242] Moreover, this exemption neither precludes any entity from presenting evidence to the Commission, nor disallows the Commission of its own accord, to investigate an allegation of market power abuse by an exempt generator. This should allay any fears that these smaller entities will be able to exercise generation market power.[1243]

Philip D. Moeller

Commissioner.

[FR Doc. E7–13675 Filed 7–19–07; 8:45 am]

BILLING CODE 6717–01–P

[1240] Such commenters include EPSA, Mirant and Constellation.

[1241] 18 CFR 35.27(a) (2006), which states ''Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.''

[1242] ''The sellers that have taken advantage of the exemption will largely qualify as Category 1 sellers, and thus will be unaffected to the extent that they will not be required to file a regularly scheduled updated market power analysis.'' Final Rule at P 321.

[1243] In defending our decision to create Category 1 sellers, the majority observes that no commenter has submitted compelling evidence that Category 1 sellers have unmitigated market power. Final Rule at P 334.