UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

(Docket No. RM04-7-000)

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

(May 19, 2006)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend 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 proposing to codify and, in certain respects, revise its current standards for market-based rates for sales of electric energy, capacity, and ancillary services. The Commission is proposing to retain several of the core elements of its current standards for granting market-based rates. However, we propose certain revisions to these standards and seek comment on other issues. The Commission also proposes to streamline certain aspects of its filing requirements to reduce the administrative burdens on applicants, customers and the Commission.

DATES: Comments are due [**insert date 60 days after publication in the FEDERAL REGISTER**]. Reply comments are due [**insert 30 days after comment date**].

Comments should be double spaced and include an executive summary.

ADDRESSES: You may submit comments, identified by Docket No. RM04-7-000, by one of the following methods:

- Agency Web Site: http://www.ferc.gov. Follow the instructions for submitting comments via the eFiling link found in the Comment Procedures Section of the preamble.
- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street N.E., Washington, D.C., 20426. Please refer to the Comment Procedures Section of the preamble for additional information on how to file paper comments.

FOR FURTHER INFORMATION CONTACT:

Kelly A. Perl (Technical Information)
Office of Energy Markets and Reliability
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 502-6421

Elizabeth Arnold (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 502-8818

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities — Docket No. RM04-7-000

NOTICE OF PROPOSED RULEMAKING

Paragraph Numbers

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities — Docket No. RM04-7-000

NOTICE OF PROPOSED RULEMAKING

(May 19, 2006)

I. Introduction

1. Pursuant to sections 205 and 206 of the Federal Power Act (FPA),[1] the Commission is proposing to amend its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal 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 authorizations and tariffs so they will be expressly conditioned on or revised to reflect certain new requirements proposed herein. The major components of this Notice of Proposed Rulemaking (NOPR) are summarized in the next section.

[1] 16 U.S.C. § 824d, 824e (2000).

II. **Background**

2. 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.

3. The courts have reviewed the Commission's market-based rate program and found that it satisfies the FPA. The FPA requires that all rates demanded by public utilities for the sale of electric energy at wholesale be found "just and reasonable."[2] The United States Supreme Court has explained that the just and reasonable standard "does not compel the Commission to use any single pricing formula."[3] The United States Court of Appeals for the D.C. Circuit has long held that "when there is a competitive market the [Commission] may rely upon market-based prices in lieu of cost-of-service regulation to

---

[2] Louisiana Energy and Power v. FERC, 141 F.3d 364, 365 (D.C. Cir. 1998) (citing 16 U.S.C. § 824d(a)) (Louisiana Energy).

[3] Mobil Oil Exploration v. United Distribution Co., 498 US 211, 224 (1991).

assure a 'just and reasonable' result."[4] The Commission's authorization of market-based rates has been found to satisfy the just and reasonable standard of the FPA.[5]

4. The Commission initiated the instant rulemaking proceeding in April 2004 to consider "the adequacy of the current four-prong 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. The comments from these technical conferences are considered in this NOPR.[7]

5. 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.[8] The April 14 Order adopted a policy that would provide sellers a

---

[4] Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993) (Elizabethtown Gas), (citing Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990)).

[5] See Louisiana Energy; Elizabethtown Gas; Consumers Energy Company v. FERC, 367 F.3d 915, 923 (D.C. Cir. 2004).

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

[7] A summary of the comments submitted in this proceeding is attached as Appendix E. A list of the commenters is included in Appendix D.

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

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.

6. On July 8, 2004, the Commission acted on 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. The Commission clarified, among other things, the types of data on which sellers and intervenors may rely, and that adjustments may be allowed in certain circumstances. The Commission also clarified that mitigation would be imposed in all markets where a seller is found to have generation market power.

7. The Commission believes it is now appropriate to revise and codify the standards for market-based rates for wholesale sales of electric energy, capacity and ancillary services. Refining and codifying effective standards for market-based rates will help customers by ensuring that they are protected from the exercise of market power. It will also provide greater certainty to sellers seeking market-based rate authority.

8. The regulations proposed herein would adopt in most respects the Commission's current standards for granting market-based rates. We believe these standards have, with the exceptions noted below, allowed the Commission to distinguish between applicants that have market power and those that do not. For example, the current interim

horizontal (generation) market power screens[9] have allowed the Commission to identify a number of smaller applicants that do not have generation market power. The Commission authorized these applicants to obtain or retain market-based rate authority, which benefits customers by encouraging new entry and by providing them with the greater flexibility in product offerings that market-based rate approval conveys. The current screens also have allowed the Commission to more accurately identify instances where certain larger sellers may possess market power. If an applicant fails our screens, this does not, however, constitute a definitive finding of market power. Rather, our current standards allow any applicant that fails these screens to demonstrate that it lacks market power in generation using the delivered price test (DPT).[10] The DPT has provided appropriate flexibility in allowing the Commission to consider the differing factual situations of particular sellers, such as those that have a responsibility for serving native load customers. The Commission proposes to continue to apply the DPT in such a flexible manner.

---

[9] As discussed below, the Commission proposes to henceforth refer to the generation market power analysis as the horizontal market power analysis.

[10] See April 14 Order at P 106 ("The [DPT] defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each suppliers' economic capacity and available economic capacity for each season/load condition. The results of the [DPT] can be used for pivotal supplier, market share and market concentration analyses.").

9. In cases where the applicant has failed the DPT, or has otherwise chosen to adopt default cost-based mitigation or to propose other cost-based mitigation (e.g., cost-based rates) or tailored mitigation, our current policies protect customers by ensuring that applicants with market power in a given area have that market power mitigated. We recognize, however, that there has been uncertainty regarding the rate methodologies to use in developing cost-based market power mitigation and the effectiveness of the existing cost-based mitigation. We therefore seek comment in this rulemaking on several issues relating to cost-based market power mitigation, including: (i) whether there should be a standard methodology for determining cost-based ceiling rates and the appropriate methodology for sales of less than one week; (ii) whether selective discounting should be allowed for sellers that have been found to have market power, or that accept a presumption of market power, and are offering power under cost-based rates; and (iii) whether a mitigated seller that seeks to sell excess power generated within a mitigated market should be required to first offer its available capacity at cost-based rates to customers within the mitigated market.

10. We also propose certain modifications to the horizontal (generation) market power screens to reflect our experience in applying them and the comments received in this proceeding. First, the Commission proposes to modify the treatment of newly-constructed generation to avoid a situation in which all generation becomes exempt from our market power analyses as new generation is constructed and older (pre-1996) generation is retired. Second, although we propose to retain the default relevant

geographic market (control area), we provide guidance as to the factors the Commission will consider in evaluating whether, in a particular case, to adopt an expanded geographic market instead of relying on the default geographic market. Third, we propose to change 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 to clarify that native load can only include load attributable to native load customers as that term is defined insection 33.3(d)(4)(i) of the Commission's regulations..[11] Fourth, we propose to allow applicants the option of using seasonal capacity instead of nameplate capacity,[12] and to retain the snapshot in time approach for the screens but to allow "known and measurable" changes (sometimes referred to as foreseeable and reasonably certain at the time of filing) for the DPT.

11. With regard to vertical market power and, in particular, transmission market power, the Commission proposes to continue the current policy under which an open access transmission tariff (OATT) is deemed to mitigate a seller's transmission market power.[13] However, in recognition of the fact that OATT violations may nonetheless

[11] 18 CFR § 33.3(d)(4)(i) (2005).

[12] Nameplate capacity is the full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

[13] See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by

(continued)

occur, we propose that violation(s) of the OATT may be cause to revoke market-based rate authority in addition to any other applicable remedies, such as civil penalties. We also note that concerns regarding the adequacy of the current OATT will be addressed in Docket No. RM05-25-000, Preventing Undue Discrimination and Preference in Transmission Service. We are today issuing a Notice of Proposed Rulemaking to reform the OATT in that docket.

12. With regard to vertical market power and, in particular, other barriers to entry, we propose to continue our current approach but provide clarification of what types of factors we would examine and we propose to combine the other barriers to entry analysis with the rest of our vertical market power analysis.

13. With regard to affiliate abuse, the Commission proposes to discontinue referring to affiliate abuse as a separate "prong" of our analysis and instead proposes to codify in our regulations an explicit requirement that any seller with market-based rate authority must

---

Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles January 1991-June 1996 ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1997), 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 relevant 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).

comply with the affiliate sales restrictions and other affiliate provisions.[14] The Commission proposes 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 proposes to retain its policy that sales of power between a franchised public utility and any of its non-regulated power sales affiliates[15] must be pre-approved by the Commission. To demonstrate that an affiliate sale is just, reasonable and not unduly discriminatory, an applicant has several options, including pricing that sale at a market index that meets certain standards, conducting an auction that reflects certain guidelines, or otherwise meeting the standards

---

[14] In the case of non-exempt wholesale generator (EWG) public utilities, for matters arising under Part II of the FPA, the term "affiliate" is defined as that term is used in section 358.3(b) and (c) (formerly section 161.2) of the Commission's regulations. Section 358.3(b) defines "affiliate" as "another person which controls, is controlled by, or is under common control with, such person." Section 358.3(c) states that "control (including the terms 'controlling,' 'controlled by,' and 'under common control with') . . . includes, but is not limited to, the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct or cause the direction of the management or policies of a company. A voting interest of 10 percent or more creates a rebuttable presumption of control." The term "affiliate" in the case of EWG public utilities is defined as "any company, 5 percent or more of the outstanding voting securities of which are owned, controlled or held with power to vote, directly or indirectly, by such company." See Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005, Order No. 667-A, 71 FR 28446 (May 16, 2006), FERC Stats. & Regs. ¶ 31, 096 (2006). (To be codified at 18 CFR section 366.1 (2006).)

[15] By "non-regulated" power sales affiliate, the Commission is referring to non-traditional power sellers including a power marketer, EWG, qualifying facilities (QFs), or other power seller affiliate, whose power sales are not regulated on a cost basis under the FPA.

set forth in Edgar.[16] An affiliate sale that has not been pre-approved under these standards will constitute a tariff violation. In addition, we reaffirm that the Commission currently requires that sales made under market-based rate tariffs, including those made to affiliates, must be reported in an Electric Quarterly Report (EQR). With regard to affiliate transactions under a market-based rate tariff, we reaffirm that we either grant or deny authorization to make affiliate sales. To the extent that we authorize an affiliate transaction, we reaffirm that, consistent with the Commission's regulations,[17] any such agreement shall not be filed with the Commission.

14. We also propose certain reforms to streamline the administration of the market-based rate program. As discussed more fully below, in an effort to streamline and simplify the market-based rate program in general, while maintaining a high degree of oversight, the Commission proposes several changes and clarifications. Significant areas of modification involve the three-year updated market power analysis (triennial review or updated market power analysis) that all sellers with market-based rate authority are required to file, and the development of a market-based rate tariff of general applicability.

15. With regard to updated market power analyses, the Commission's current general practice is to require an updated market power analysis to be submitted within three years

[16] Boston Edison Company Re: Edgar Electric Energy Co., 55 FERC ¶ 61,382 (1991) (Edgar) (Describing types of evidence that can be used to demonstrate lack of affiliate abuse.)

[17] See 18 CFR § 35.1(g) (2005).

from the date of the Commission order granting the seller market-based rate authority or accepting the previous triennial review. The Commission proposes to modify that general practice and put in place a structured, systematic review to assist the Commission in analyzing sellers in markets based on a coherent and consistent set of data. In particular, the Commission proposes to modify the requirements for filing updated market power analyses in two ways. First, the Commission proposes to establish two categories of sellers with market-based rate authorization. The first category, Category 1 (approximately 550 sellers), would consist of 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 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 such facilities are limited and discrete and do not constitute an integrated grid[18]) and must present no other vertical market power issues. Category 1 sellers would not be required to file a regularly scheduled triennial review. The Commission would monitor any market power

[18] See, e.g., Black Creek Hydro, Inc., 77 FERC ¶ 61,232 (1996).

concerns for these sellers through the change in status reporting requirement,[19] and through ongoing monitoring by the Commission's Office of Enforcement.

16. The second category, Category 2 (approximately 600 sellers), would include all sellers that do not qualify for Category 1. Category 2 sellers, in addition to the change in status reports, would be required to file regularly scheduled triennial reviews.[20] To ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposes to require each Category 2 seller to file updated market power analyses for its relevant geographic markets (default and any proposed alternative markets) on a schedule that will allow examination of the individual seller at the same time that the Commission examines other sellers in these relevant markets and contiguous markets within a region from which power could be imported. The Commission would continue to make findings on an individual seller basis, but would have before it a complete picture of the uncommitted capacity and simultaneous import capability into the relevant geographic markets under review.

17. A second significant change is our proposal to adopt a market-based rate tariff of general applicability (MBR tariff), applicable to all sellers authorized to sell electric

---

[19] See 18 CFR § 35.27(c) (2005) (reporting requirement for any change reflecting a departure from the characteristics the Commission relied upon in granting market-based rate authority). Failure to timely file a change in status report would constitute a tariff violation.

[20] Failure to timely file a triennial review would constitute a tariff violation.

energy, capacity or ancillary services at wholesale at market-based rates. Further, the Commission proposes that, rather than each entity having its own MBR tariff, which can result in dozens of tariffs for each corporate family with potentially conflicting provisions, each corporate family would have only one tariff, with all affiliates with market-based rate authority separately identified in the tariff. This will reduce the administrative burden and confusion that occurs when there are multiple, and potentially conflicting, tariffs in a single corporate family. Our intent to streamline the terms of an MBR tariff is not to reduce the flexibility of sellers and customers in negotiating the terms of individual transactions. Rather, this flexibility will continue to exist. The purpose of a tariff of general applicability that requires the seller to comply with the applicable provisions of the market-based rate regulations is simply to codify, on a consistent basis, the basic requirements of market-based rate authorization.

III. Discussion

A. Horizontal Market Power

1. Current Policy

a. Test for Generation Market Power

18. In the April 14 Order, the Commission adopted two indicative screens for assessing generation market power that provide a rebuttable presumption of whether market power exists for a utility applying to obtain or retain market-based rate authority. Sellers that do not pass the initial screens are, among other things, allowed to provide additional evidence for Commission consideration. Such an approach allows the

Commission to concentrate its efforts on sellers that may possess generation market power while screening out those sellers that do not pose such concerns.

19. The Commission uses two indicative screens for assessing whether a particular seller raises any generation market power concerns, each with its own specific focus and attributes: a pivotal supplier analysis based on uncommitted capacity at the time of the market's annual peak demand; and a market share analysis of uncommitted capacity applied on a seasonal basis. If a seller passes both screens, there is a rebuttable presumption that the seller does not possess market power in generation. However, the Commission allows intervenors to present evidence to rebut the presumption. On the other hand, if a seller fails either screen, this creates a rebuttable presumption that market power exists in generation.[21] In this instance, the seller may: (1) file a more robust market power study, the DPT;[22] (2) file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; or (3) inform the Commission that it will either adopt the default cost-based rates discussed in the April 14 Order or propose other cost-based rates and submit cost support for such rates. Before

[21] In such a case, the Commission will institute a section 206 proceeding and such a seller's rates prospectively will be made subject to refund until a final determination of market power is made or the seller accepts a presumption of market power and so mitigates. April 14 Order, 107 FERC ¶ 61,018 at n. 10.

[22] The only additional market power study allowed is the DPT. However, the Commission allows such sellers to present evidence, based on historical wholesale sales data, in support of a contention that, notwithstanding the results of the two indicative screens, they do not possess market power.

the Commission considers the DPT, the seller must be found to have failed one (or both) of the two indicative screens or so concede.[23] Accordingly, the DPT is considered as an alternative study to support the grant or continuation of market-based rate authority. In all cases, the seller or intervenors may present evidence such as historical wholesale sales data to support their opinion of whether the seller does or does not possess market power.

20. Section 35.27(a) of the Commission's regulations states that "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."[24] Sellers meeting the criteria of section 35.27(a) of our regulations, as clarified in LG&E Capital,[25] may provide evidence demonstrating that they satisfy this section of our regulations rather than submit a generation market power analysis. However, if a seller sites generation in an area where it or its affiliates own or control other generation assets, the seller must provide an analysis regarding whether its new capacity (i.e., post-July 9, 1996), when added to existing capacity, raises generation market power concerns.

---

[23] April 14 Order, 107 FERC ¶ 61,018 at P 37.

[24] 18 CFR 35.27(a) (2005).

[25] LG&E Capital Trimble County LLC, 98 FERC ¶ 61,261 (2002) (LG&E Capital).

21. Alternatively, a seller may forego submitting a generation market power analysis and accept a presumption of market power and go directly to mitigation by proposing case-specific mitigation that eliminates the ability to exercise market power, or agreeing to the default rates discussed below. Under such circumstances there will be a presumption of market power in all of the default relevant markets.

22. If a seller's proposed mitigation[26] does not eliminate its ability to exercise market power, then the seller may not charge market-based rates in the geographic area(s) where market power is found, and the seller is subject to cost-based default rates or other cost-based rates that the seller proposes and the Commission approves. The Commission's default rates are as follows: (1) sales of power of one week or less must 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 must 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 must be priced at a rate not to exceed the embedded cost of service, and the contract must be filed with the Commission for review. Mitigated

[26] Proposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate. For example, an applicant could propose to transfer operational control of enough generation to a third party such that the applicant would satisfy our generation market power concerns.

sellers must first receive Commission approval for each long-term power sale prior to transacting.[27]

b. Additional Requirement for Transmission Owners

23. In addition, 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., 110 FERC ¶ 61,127 (2005). 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

[27] The Commission notes here that, to the extent a party believes market power is being exerted in the course of negotiating a long-term purchase, such party may file a complaint pursuant to section 206 of the FPA.

assumptions used historically by the transmission provider in approximating its control area import capability.

24. A seller may provide a streamlined application to show that it passes the indicative screens. Thus, with respect to simultaneous import capability, if a seller can show that it passes the screens for each relevant geographic market without considering imports, no such simultaneous import analysis needs to be provided. Further, the Commission recognizes that certain sellers will not have the ability to perform a simultaneous import capability study. Accordingly, if a seller demonstrates that it is unable to perform a simultaneous import capability study for the control area in which it is located, the seller may propose to use a proxy amount for transmission limits. Such proposals are considered on a case-by-case basis.

c. Relevant Geographic Markets

25. The default relevant geographic markets under both screens are first, the control area market where the seller is physically located, and second, the markets directly interconnected to the seller's control area market (first-tier control area markets).[28] In this default analysis, the Commission considers only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant

---

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

market. Sellers located in and a member of regional transmission organizations (RTO)/independent system operators (ISO)[29] that perform functions such as single central commitment and dispatch with a single energy market and Commission-approved market monitoring and mitigation may consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of completing their analyses.[30] Currently, these markets are operated by PJM Interconnection, LLC (PJM), ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), Midwest Independent Transmission System Operator (Midwest ISO) and California Independent System Operator Corporation (CAISO). For sellers whose assets are physically located geographically within the RTO/ISO boundaries, there is only one default relevant market for those assets, and that is the RTO/ISO in which they are located and are a member. Likewise, where a generator is interconnecting to a non-affiliate owned transmission system, there is only one relevant market, the control area in which the generator is located.

---

[29] We note that the membership status described is such that the seller that owns transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid has turned over operational control of those transmission assets to the RTO/ISO.

[30] LG&E Energy Marketing, Inc., 111 FERC ¶ 61,153 (2005) (noting that where applicants are members of the Midwest ISO and their control area is within the Midwest ISO geographic footprint, the default relevant geographic market for the generation market power analyses is the Midwest ISO).

26. The Commission allows 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. For example, sellers or intervenors can present evidence that the relevant market is broader (or more limited) than a particular control area. However, applicants presenting evidence that the relevant market is larger or smaller than the default relevant market must first complete the screens based on the default market as discussed above. To the extent some other geographic market is studied, the proponent of using that alternative market must adhere to including all monitored lines/constraints and critical contingencies that were historically applied during the seasonal peaks in assessing available transmission for non-affiliate transmission customers (i.e., consistent with Open Access Same-Time Information System (OASIS)). Sellers and intervenors may also provide evidence that, because of internal transmission limitations (e.g., load pockets), the relevant market is smaller than the control area.

d. Performance of the Indicative Screens

27. Both the pivotal supplier analysis and the market share analysis recognize utilities' obligations to serve native load. Because utilities generally use the same generating units to make off-system wholesale sales and to serve native load, and because the amount of generation needed to serve native load can vary from hour to hour, some reasonable proxy is needed to represent the amount of generation that is needed to serve native load. Accordingly, the pivotal supplier analysis, for both sellers and competing suppliers, uses

the average of the daily native load peaks during the month in which the annual peak demand day occurs as a proxy for native load obligation. The market share analysis for both sellers and competing suppliers uses the native load obligation on the minimum peak demand day for a given season.

28. In the pivotal supplier screen, a market participant's uncommitted capacity is determined by adding the total nameplate capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales. To calculate the net uncommitted supply available to compete at wholesale, the wholesale load proxy (annual peak load less the native load proxy discussed above) is deducted from total uncommitted capacity in the market.[31] 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.

29. In the market share analysis, uncommitted capacity is defined similarly to the pivotal supplier screen, with the additional deduction for planned outages that were done in accordance with good utility practice. Under the market share analysis, a seller that has less than a 20 percent market share in the relevant market for all seasons is

[31] April 14 Order, 107 FERC ¶ 61,018 at P 99.

considered to satisfy the market share analysis.[32] A seller with a market share of 20 percent or more in the relevant market for any season has a rebuttable presumption of market power but can present historical evidence to show that the seller satisfies the Commission's generation market power concerns.[33]

30. In addition, any seller, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate. In performing all screens, sellers are required to prepare them as designed,[34] and must use the most recently available unadjusted 12 months' historical data as a snapshot in time.[35] Sellers filing abbreviated studies may request waiver of the full data requirements.

---

[32] The 20 percent threshold is consistent with section 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."

[33] The other evidence the Commission will consider is historical sales and/or access to transmission to move supplies within, out of, and into a control area market.

[34] Sellers presenting evidence that the relevant market is larger or smaller than the default relevant market (i.e., control area) must first complete the screens based on the default relevant geographic market.

[35] The Commission clarified on rehearing that it will allow adjustments necessary to perform the screens if the seller fully justifies the need for and methodology used for the adjustment and files all workpapers supporting the adjustments and documenting the source data used. July 8 Order, 108 FERC ¶ 61,026 at P 119.

e. The Delivered Price Test (DPT)

31. 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 Commission's DPT.[36] The DPT is used to analyze the effect on competition for transfers of jurisdictional facilities in section 203 proceedings,[37] using the framework described in Appendix A of the Merger Policy Statement as revised in Order No. 642.[38] The DPT is an established test that has been used routinely to analyze market power in the merger context for many years, and it has been affirmed by the courts.[39]

32. The DPT defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's

---

[36] April 14 Order, 107 FERC ¶ 61,018 at P 105-12.

[37] 16 U.S.C. 824b (2000).

[38] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 F. R. 68595 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,044 (1996), reconsideration denied, Order No. 592-A, 62 F. R. 33341 (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 F. R. 70984 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 (2000), order on reh'g, Order No. 642-A, 66 F. R. 16121 (2001), 94 FERC ¶ 61,289 (2001).

[39] See, e.g., Wabash Valley Power Associates, Inc. v. FERC, 268 F. 3d 1105 (D.C. Cir. 2001).

economic capacity and available economic capacity for each season/load period.[40] The results of the DPT are used for pivotal supplier, market share and market concentration analyses. Using the economic capacity for each supplier, sellers are required to provide pivotal supplier, market share and market concentration analyses. Examining these three measures with the more robust output from the DPT allows sellers to present a more complete view of the competitive conditions and their positions in the relevant markets.

33. Under the DPT, to determine whether a seller is a pivotal supplier in each of the season/load periods, sellers are required to compare the load in the relevant market to the amount of competing supply. 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 for the relevant period. The analysis using available economic capacity to account for sellers' and competing suppliers' native load commitments is also required.

34. Each supplier's market share is calculated based on economic capacity, the DPT's analog to installed capacity. The market shares for each season/load period reflect the costs of the seller's and competing suppliers' generation, thus giving a more complete picture of the seller's ability to exercise market power in a given market.

---

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

35. Sellers preparing a DPT also must calculate the market concentration using the Hirschman-Herfindahl Index (HHI) based on market shares.[41] For the DPT, a showing of an HHI less than 2,500 in the relevant market for all season/load periods for sellers that have also shown that they are not pivotal and do not possess more than a 20 percent market share in any of the season/load periods would constitute a showing of a lack of market power, absent compelling contrary evidence. We will, however, consider all relevant facts and circumstances in reviewing a DPT, (including native load obligations), and we will balance the record evidence in determining whether or not the seller has generation market power. Thus, even sellers that exceed the foregoing thresholds may receive market-based rates under appropriate circumstances.[42]

36. Sellers and intervenors may present evidence such as historical wholesale sales data, which can be used to calculate market shares and market concentration and to refute or support the results of the DPT. The Commission encourages sellers to present the most complete analysis of competitive conditions in the market as the data allow. In this regard, the Commission allows the introduction of such evidence beyond the most recent 12 months. The use of unadjusted historical sales and transmission data will provide an

---

[41] 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 = $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2 = 400 + 400 + 400 + 400 + 400 = 2,000$.

[42] See, e.g., Kansas City Power & Light Co., 113 FERC ¶ 61,074 at P 30-35 (2005) (Kansas City); Acadia Power Partners, LLC, 113 FERC ¶ 61,073 at P 40-45 (2005) (Acadia).

accurate depiction of actual market activity. Therefore, the Commission requires sellers submitting historical sales and transmission data as evidence to submit the actual data.

37. The FPA requires that all rates charged by public utilities for the transmission or sale for resale of electric energy be just and reasonable.[43] Thus, where a market-based rate seller is found to have market power in generation (e.g., after reviewing a seller's DPT), it is incumbent upon the Commission to either reject such rates or to ensure that adequate mitigation measures are in place to ensure that the rates are just and reasonable. The Commission provides default cost-based rates to ensure that wholesale rates are just and reasonable. If a seller does not pass the generation market power screens, or foregoes the screens entirely, the Commission sets the just and reasonable rate at the default cost-based rate unless it approves different mitigation based on case-specific circumstances.

38. For sellers that have a presumption of market power in generation (e.g. those failing one or both of the indicative screens), the Commission will institute a section 206 proceeding and the seller's rates will prospectively be made subject to refund.[44] For sellers already charging market-based rates, market-based rates will not be revoked and

[43] 16 U.S.C. 824d(a) (2000).

[44] The refund floor would be the default cost-based rates or, if applicable, any case-specific cost-based rates proposed by the seller and accepted by the Commission. Accordingly, the seller has certainty as to its potential refund obligation, if any. April 14 Order, 107 FERC ¶ 61,018 at n. 143.

cost-based rates will not be imposed until the Commission issues an order making a definitive finding that the seller has market power in generation (typically, after the Commission has ruled on a DPT analysis) or, where the seller accepts a presumption of market power, an order is issued addressing whether default cost-based rates or case-specific cost-based rates are to be applied. The Commission will revoke the market-based rate authority in all geographic markets where a seller is found to have market power in generation.[45]

2. Proposal

39. The Commission adopted the indicative generation market power screens in the April 14 Order for interim purposes, and instituted the instant rulemaking proceeding to, among other things, review these screens and, as a whole, the horizontal market power portion of the Commission's four-prong analysis. The Commission has gained considerable experience with the analysis since the April 14 Order and believes that in general the current screens work well to identify the subset of sellers that require additional review. Therefore, we propose to continue to use the screens adopted in the April 14 Order as well as the overall approach to analyzing generation market power set forth in the April 14 Order, including the procedural options available to sellers and the use of the DPT. However, commenters have raised some valid concerns and,

[45] The seller has the option of withdrawing its market-based rate request in whole or in part.

accordingly, the Commission proposes certain modifications to the screens as adopted in the April 14 Order, such as adjustments to the native load proxy. Furthermore, while reaffirming the screens, we propose that henceforth these screens should be referred to as our horizontal market power analysis. In particular, our horizontal analysis will include, as discussed in the April 14 Order, the two indicative screens and the DPT as necessary.

a. Indicative Screens and DPT Criteria

40. Because the indicative screens are intended only to identify the sellers that require further review, we propose to retain the 20 percent threshold for the wholesale market share screen. The screens are indicative, not definitive. Indeed, pursuant to the horizontal market power analysis where an applicant is seeking to obtain or retain market-based rate authority, 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. Instead, where a seller fails one of the indicative screens, a section 206 proceeding is instituted to more closely examine a seller's potential for exercising horizontal market power and does not mean a definitive finding has been made. Failure to pass either of the indicative screens creates a rebuttable presumption of market power. A seller that fails the initial screens is given 60 days from the date of issuance of an order finding a screen failure to: (1) file a DPT analysis; (2) file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; or (3) inform the

Commission that it will adopt the default cost-based rates or propose other cost-based rates and submit cost support for such rates.[46]

41. Some commenters argue that the 20 percent threshold is too low; others argue that it is too high. The Commission believes that the 20 percent threshold strikes the right balance in seeking to avoid both "false negatives" and "false positives" and proposes to continue using 20 percent. Because the presumption of horizontal market power established by the failure of the wholesale market share screen is rebuttable, coupled with the adjustment to the native load proxy discussed below, sellers should be assured that the 20 percent threshold is not unnecessarily stringent.

42. We also propose 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. The pivotal supplier analysis examines the seller's market power during the annual peak. The hours near that point in time are the most likely times that a seller will be a pivotal supplier.

43. Similarly, for the DPT analysis, we propose to retain our current threshold including 2,500 for HHIs, as well as our current practice of weighing all the relevant factors in the analysis, in determining whether a seller does or does not have horizontal market power. We propose to continue to do so on a case-by-case basis, weighing such factors as available economic capacity, economic capacity, HHIs, and other historical

[46] April 14 Order, 107 FERC ¶ 61,018 at P 208.

wholesale sales data. The thresholds are well-established and appropriate, allowing the Commission to make a reasoned determination after reviewing all the evidence in the record. The DPT does not function like the initial screens in that the failure of either the economic capacity or available economic capacity analyses does not result in an automatic failure as a whole.[47]

b. Native Load

44. To reduce the number of "false positives" in the wholesale market share screen, however, we propose to adjust the native load proxy. Many commenters have noted that the current native load proxy for the market share screen is too limited and results in too much uncommitted capacity attributable to the seller. The Commission stated in the April 14 Order that by using the two screens together, the Commission is able to measure market power both at peak and off-peak times, and the ability to exercise market power both unilaterally and in coordinated interaction with other sellers. In the April 14 Order, the Commission adopted the native load proxy for the wholesale market share screen in order to balance the concerns of market participants. We now believe that the current proxy used in the market share screen may be too conservative. Accordingly, the Commission proposes to change the allowance for the native load deduction under the market share 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

[47] Kansas City, 113 FERC ¶ 61,074 at P 30; Acadia, 113 FERC ¶ 61,073 at P 40.

the market share screen consistent with the deduction allowed under the pivotal supplier screen. We propose to retain a season-by-season analysis. For example, the proxy for summer would be the average native load peak for June, July and August. The pivotal supplier screen's native load proxy would remain unchanged from its current proxy of the average of the daily native load peaks during the month in which the annual peak day load occurs. We seek comments on our proposal.

45. We believe there has been some inconsistency in the way in which sellers have reflected native load in performing both the screens and the DPT analysis. For this reason, we also propose to clarify that for the horizontal market power analysis, native load can only include load attributable to native load customers as defined in section 33.3(d)(4)(i) of the Commission's regulations,[48] as it may be revised from time to time. We seek comments on this proposal.

c. <u>Control and Commitment of Generation</u>

46. The Commission stated 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

[48] 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.

capacity to the buyer.[49] 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.[50]

47. The Commission has stated that contracts can confer the same rights of control of generation or transmission facilities as ownership of those facilities.[51] In short, 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

---

[49] July 8 Order, 108 FERC ¶ 61,026 at P 65.

[50] Id. at P 66.

[51] Citizens Power and Light Corp., 48 FERC ¶ 61,210 at 61,777 (1989) (Citizens Power). 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 Plasma Power, L.L.C., 102 FERC ¶ 61,265 at P 33-36 (2003) (D.E. Shaw) (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 Plant Management, Ltd., 109 FERC ¶ 61,315 at P 15 (2004) (R.W. Beck) (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).

performing the generation market power screens.[52] 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.[53]

48. In recent years, some owners have turned to third parties to manage the day-to-day activities of running and dispatching plants and/or selling output. Such third-party contractors, often referred to as energy managers and/or asset managers, can be responsible for multiple facilities through multiple energy management agreements. These management agreements may, directly or indirectly, transfer control of the capacity. The Commission is concerned that there may be instances where, in effect, control of capacity has changed hands, but this capacity has not been attributed to the correct seller for purposes of calculating our market screens.

49. 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.[54] Likewise, in providing guidance regarding events

[52] July 8 Order, 108 FERC ¶ 61,026 at P 65.

[53] 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 January 2001-December 2005 ¶ 31,175 at P 47, order on reh'g, Order No. 652-A, 111 FERC ¶ 61,413 (2005).

[54] D.E. Shaw, 102 FERC ¶ 61,265 at P 33-36; R.W. Beck, 109 FERC ¶ 61,315 at P 15.

that trigger a requirement to submit a notice of change in status, the Commission has 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.[55] Although this analysis is inherently fact-dependent to some degree, the Commission is interested in providing greater certainty and clarity in this area, which should increase the uniformity in reporting capacity and reduce the possibility of tariff violations. The Commission therefore seeks comment on whether it should make certain generic findings, or create certain generic presumptions, regarding the indicia of control. Specifically, the Commission seeks comment on whether any of the following functions should merit a finding or presumption of control and, if so, on what basis: directing outages, fuel procurement, plant operations, energy and capacity sales, and/or credit and liquidity decisions. Alternatively, rather than focusing on these discrete items, should the Commission establish a presumption of control for any entity that has some discretion over the output of the plant(s) that it manages? Would such an approach promote greater certainty and better align the test with the ultimate goal of attributing plant capacity to those who control its output? If the Commission adopted such a presumption, how should it address instances where discretion over plant output may be shared between more than one party? We also propose to clarify that, in the event we adopt any such

---

[55] Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 47.

presumptions, the Commission would nonetheless allow individual sellers to rebut the presumption on the basis of their particular facts and circumstances.

50. The Commission also proposes to clarify that an entity (such as an asset manager or other such 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 (e.g., the entity must provide a horizontal and vertical market power analysis and include in its horizontal analysis all assets it owns or controls in the relevant market). If such an entity controls an asset from which jurisdictional power sales are being made and such entity does not have a rate on file, it is violating section 205 of the FPA.[56] We wish to emphasize, however, that our intent is not to limit or stifle the provision of energy management services. These services can provide benefits to customers and the marketplace. Rather, our intent is to provide greater certainty and clarity as to when such arrangements confer control so that the capacity being controlled is properly reported and the entity assuming such control has received the necessary authorizations under the FPA for providing jurisdictional services.

d. Relevant Geographic Market

51. The Commission proposes to continue to use its current approach with regard to the relevant geographic market. The default relevant geographic market is the control

[56] 18 U.S.C. § 824d (c) (2000).

area where the seller is physically located and 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 proposes to continue to designate the RTO/ISO in which a seller is located and is a member as the default relevant geographic market for RTO/ISOs with sufficient market structure and a single energy market, and not require sellers to consider, as part of the relevant market, markets first-tier to the RTO/ISO in which the seller is located and is a member.[57] We believe that designating a default relevant geographic market provides sellers and intervenors a measure of certainty regarding the relevant market. We note that the default market seems to be acceptable to most sellers as there have been relatively few sellers who have proposed to expand or contract the default relevant geographic market.

52. We note that the North American Electric Reliability Council (NERC) no longer uses the designation of control area since it approved the "NERC Reliability Functional Model" on February 10, 2004. We seek 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 should it be specified and how readily available is the relevant data.

[57] April 14 Order, 107 FERC ¶ 61,018 at P 187.

53. The Commission proposes to continue to provide flexibility by allowing sellers and intervenors to present evidence that the market is smaller or larger than the default market. To that end, we propose to provide guidance regarding the demonstration that a relevant geographic market is larger than a default geographic market by identifying the types of factors the Commission will consider in evaluating whether to adopt an expanded geographic market in a particular case instead of relying on the default geographic market (generally, the control area).

54. Reaching beyond the default market in which an entity is located can mean addressing additional physical and other challenges than when trading within that market. When assessing an expanded geographic market pursuant to the horizontal analysis, the Commission 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. Any proposal to use an expanded market (i.e., a market other than the default geographic 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. In this regard, we propose to require that a demonstration be made based on historical data. In addition, we would require that a sensitivity analysis be performed analyzing under what circumstance(s) transmission constraints would bind.

55. The Commission also considers whether there is other evidence that would support the existence of an expanded market. In deciding whether customers may be considered as part of an expanded geographic market, the Commission will also 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.

56. Such evidence submitted to show that the applicant's customers have access to resources outside of their control area at terms and conditions similar to those at which they can access resources inside the control 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 control 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 control areas; 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.

57. In determining whether two or more control areas are a single market the Commission would weigh, on a case-by-case basis, all the 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.

58. We seek comment on our proposed guidance and, in particular, whether there are other factors the Commission should consider when assessing a proposed expanded market. Are there any factor(s) that should be given more weight or are essential in determining the scope of the market (e.g., are there any factors that, if not satisfactorily addressed, would preclude the need to consider any other factors)? Should the Commission apply the same criteria when determining whether the geographic market is smaller than the default geographic market?

59. In addition, as discussed previously, the Commission proposes to designate the RTO/ISO in which the seller is located and is a member as the default relevant geographic market for RTO/ISOs with sufficient market structure and a single energy market. We believe the added protections provided in structured markets with market monitoring, market power mitigation and transparency generally result in a market where attempts to exercise market power would be sufficiently mitigated.

60. In the April 14 Order, the Commission identified PJM, ISO-NE, NYISO, and CAISO as meeting the criteria for being considered a single market for purposes of

performing the generation market power screens.[58] The Commission also stated that, applicants can incorporate the mitigation they are subject to in ISO/RTO markets as part of their market power analysis. For example, if a market power study showed that an applicant had local market power, the applicant could point to RTO mitigation rules as evidence that this market power has been adequately mitigated. In a later order, [59] the Commission found that the Midwest ISO also met the criteria for being considered a single market for purposes of performing the generation market power screens.

61. However, our experience with corporate mergers and acquisitions indicates that these same RTOs have, at times, been divided into smaller submarkets for study purposes because frequently binding transmission constraints prevent some potential suppliers from selling into the destination market.[60] Therefore, the Commission seeks 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 geographic market for the horizontal market power analysis. In particular, should the Commission continue its approach of considering the entire geographic region as the default relevant market? Should the Commission

[58] Id. at 187.

[59] Alliant Energy Corporate Services, Inc., 109 FERC ¶ 61,289 at P 31 (2004).

[60] Examples of these submarkets include ISO-NE's Southwest Connecticut, NYISO's East of Central East (Zones F through K), PJM-East (roughly New Jersey, Southeastern Pennsylvania and the Delmarva Peninsula), Midwest ISO excluding Wisconsin-Upper Michigan (WUMS), and CAISO's SP15.

consider the entire geographic region for purposes of the indicative screens but consider RTO/ISO submarkets for purposes of the DPT. In addition, should the Commission adopt general criteria to define submarkets? If so, what criteria should the Commission adopt?

62. Lastly, if the Commission determines that an RTO/ISO submarket is the appropriate default geographic region in a particular case and an applicant is found to have market power within that submarket, should the Commission consider mitigation in addition to existing RTO market monitoring and mitigation?

e. Use of Historical Data

63. We propose to retain the "snapshot in time" approach for the screens, i.e., sellers must use the most recently available unadjusted 12 months' historical data.[61] Historical data are more objective, readily available, and less subject to manipulation than future projections; therefore, the Commission will continue to preclude adjustments to historical data with regard to the indicative screens, with the following exception. We propose to continue to permit sellers to make adjustments to data that are necessary to perform the screens provided that the applicant fully justifies the need for the adjustments, justifies the methodology used, provides all workpapers in support, and documents the source data. For example, an adjustment could be allowed where needed data is available only

[61] In accordance with the proposed filing schedule discussed below, data for the indicative screens must track the calendar year previous to the year designated for filing.

for a region that is not identical to the seller's control area in order to put it in a form that can be used in the analysis as designed.[62]

64. However, we propose in the DPT analysis to allow applicants and intervenors to account for changes in the market that are known and measurable at the time of filing.[63] This proposal mirrors the Commission's approach in connection with its merger analysis. In Order No. 642, we stated that we intend to consider current and reasonably foreseeable regional developments as part of our merger analysis. In the Merger Policy Statement, we adopted the U.S. Department of Justice / Federal Trade Commission Horizontal Merger Guidelines[64] as the analytical framework for analyzing the effect on competition. Those guidelines "address the issue of changing market conditions by stating that '[t]he Agency will consider reasonably predictable effects of recent or ongoing changes in market conditions in interpreting market concentration and market share data.'"[65] Examples of known and measurable changes in the market that would be allowed include new long-term contracts, expiration of long-term contracts, planned and imminent plant deactivations/retirements, and planned and imminent plant additions, regardless of

---

[62] July 8 Order, 108 FERC ¶ 61,026 at P 119.

[63] See 18 CFR § 35.13(a) (2005).

[64] U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines (1997) (DOJ/FTC Guidelines).

[65] Oklahoma Gas and Electric Company and NRG McClain LLC, 105 FERC ¶ 61,297 (2003) (OG&E), citing the DOJ/FTC Guidelines, § 1.521.

ownership. Sellers who elect to adjust historical data to reflect known and measurable changes would be required to perform the analysis using the most recent historical data and then provide a sensitivity analysis including adjustments for all known and measurable changes in the market and not just those advantageous to the seller.[66] Applicants and intervenors proposing known and measurable changes to be considered in the DPT analysis will bear the burden of proof for their adjustments to historical data. We seek comments 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, we seek comments on exactly what types of changes should be allowed and under what circumstances.[67]

f. Reporting Format

65. As suggested by a commenter, we propose to require all sellers to submit the results of their indicative screen analysis in a uniform format to the maximum extent

[66] See Western Resources, Inc., 65 FERC ¶ 61,106 (1993).

[67] For example, in OG&E, the Commission accepted one change as known and measurable and rejected another. Specifically, the Commission found that the expiration of a long-term power sales contract within a year was a known and measurable change and should be part of the base case analysis (105 FERC ¶ 61,297 at P 33). In the same order, the Commission found that an upgrade of a transmission facility that was identified by the Southwest Power Pool as a persistent limiting facility, but was not under construction or even in the planning stage, was not "a foreseeable and reasonably certain change in the market" and therefore should not be part of the base case analysis (id. at P 32).

practicable. This format will promote consistency and will aid the Commission in the decision-making process. Sellers must cross reference the inputs with the data and workpapers they otherwise submit including those in accordance with Appendix G of the April 14 Order. Use of a uniform format for reporting results is not intended to limit other workpapers the seller may wish to submit. The format we propose to adopt can be found in Appendix C. We seek comments on this proposal.

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

66. Section 35.27(a) of the Commission's regulations 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.[[68]]

67. The Commission clarified in the April 14 Order that some sellers with capacity built after July 9, 1996 (section 35.27(a) exemption) may avoid submitting a horizontal market power analysis if they meet the requirements of section 35.27(a) of the Commission's regulations. The Commission stated that, as it indicated in Order No. 888, it will consider whether a seller citing section 35.27(a) nevertheless possesses horizontal market power if specific evidence is presented by an intervenor, and a seller still must study whether its new capacity, when added to existing capacity, raises horizontal market

[68] 18 CFR 35.27(a) (2005).

power concerns.[69] As the Commission stated in Order No. 888, the evaluation of market-based rates for existing capacity will include consideration of new capacity.[70]

68. 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 applicant is not required to provide a horizontal market power analysis because of the exemption under section 35.27(a).[71]

69. Although we remain committed to encouraging new entry of generation, we are concerned that the continued use of the section 35.27(a) exemption may become too broad. Over time, this exemption would encompass all market participants as all pre-July 9, 1996 generation is retired. For this reason, some commenters suggest that the Commission should eliminate the exemption altogether.[72]

70. We agree with these commenters that our current practice will have unintended adverse consequences over time and therefore should be reformed. Accordingly, we propose to eliminate the express exemption provided in section 35.27(a), but to do so in a manner that will not act as a disincentive for the construction of new generation. As

---

[69] April 14 Order, 107 FERC ¶ 61,018 at P 115, 116.

[70] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,657.

[71] April 14 Order, 107 FERC ¶ 61,018 at P 38.

[72] American Public Power Association (APPA) Comments (March 15, 2005) at P 35.

explained further below, this change will not affect many sellers, given that they already are required to include all new capacity when submitting a market analysis for their pre-1996 generation. Further, our proposal will assure that all generation is treated on an equal footing, such that market participants with similar market shares in the same geographic market are not treated differently based solely on the vintage of their assets.

71. Under this proposal, the 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 and their affiliates' generation was built after July 9, 1996, must provide a horizontal market power analysis of their generation. Because the Commission allows an applicant to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any additional burden imposed by the proposed elimination of the section 35.27(a) exemption will be minimal.[73]

---

[73] April 14 Order, 107 FERC ¶ 61,018 at P 117. In the April 14 Order, the Commission explained that appropriate simplifying assumptions are those assumptions that do not affect the underlying methodology utilized by the generation market power screens. For example, if an applicant passes our generation market power screens by only considering the control area market's host utility as a competitor, the Commission foresees no benefit from completing a study to include other competitors. Similarly, if an applicant would pass the screens without considering competing supplies from adjacent control areas, the applicant need not include such imports in its studies. With regard to a new generator, such an applicant may base its horizontal market power analysis on the most recently approved study for the control area in which it is located.

72. Further, with 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. However, as discussed above, because the Commission allows for a streamlined analysis, including simplifying assumptions, where appropriate, any additional burden imposed by the proposed elimination of the section 35.27(a) exemption will be minimal. In addition, the Commission anticipates that those entities that otherwise would have relied on the exemption will, in most cases, qualify as Category 1 sellers and thus no longer be required to file triennial reviews.

73. By proposing to eliminate the express exemption set forth in section 35.27(a), we are not proposing to require sellers with market-based rate authority to submit a new horizontal market power analysis (i.e., perform the generation market power screens) each time that they add a new generating unit. Rather, a seller with market-based rate authority would be required to file a "change in status" report under Order No. 652 notifying the Commission of the acquisition of additional generation,[74] the same requirement that exists today. Such sellers are not required to file a market power

[74] Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 68. The threshold of additional generation that triggers the reporting requirement is a net increase of 100 MW or more. See Order No. 652-A, 111 FERC ¶ 61,413 at P 24-25.

analysis of their generation with their change in status filing, nor do we propose they should.[75]

74. Thus, our proposal to eliminate section 35.27(a) should not impose significant additional burdens on new generation or otherwise deter new entry. We seek comments on this proposal.

h. Nameplate Capacity

75. Based on our experience, we propose to allow sellers the option of using seasonal capacity instead of nameplate capacity as currently required. The seller must be consistent in its choice and use one or the other measure of capacity ratings throughout the analysis. The use of seasonal capacity ratings we believe more accurately reflects the seasonal real power capability andis not inconsistent with industry standards, and therefore it may be more convenient for sellers to acquire and compile the associated data. In addition, we do not think the use of such ratings will materially impact results. We seek comment on this proposal, including comment as to whether this information is publicly available to all market participants.

i. Transmission Imports

76. We propose to continue our use of limiting capacity that can be imported into a relevant market to the results of a simultaneous transmission import capability study, and

[75] Further, in the event the seller acquires existing generation, it may also need to seek approval therefor consistent with the provisions of section 203 of the FPA as amended. 16 U.S.C. 824b (2000). Energy Policy Act of 2005 §§ 261 et seq., Pub. L. No. 109-58, 199 Stat. 594 (2005) (EPAct 2005).

to reaffirm several aspects of the requirements regarding how to properly construct a simultaneous transmission import capability study for use in the indicative screens and the DPT.

77. The simultaneous transmission import capability study is intended to provide a reasonable simulation of historical conditions. In particular, the simultaneous transmission import capability study is not the theoretical maximum import capability or a best import case scenario. It is a benchmark of 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). The analysis should not deviate from OASIS practice during each historical seasonal peak. Appendix E of the April 14 Order states that the power flow cases should represent the transmission provider's tariff provisions and all firm/network reservations held by seller/affiliate resources during the most recent seasonal peaks. We propose to reaffirm that "all" means both short- and long-term firm/network reservations.

78. In addition to the power flow cases, as noted in Appendix E of the April 14 Order, the seller must supply supporting documentation, and this documentation should include the operational practices historically used, reliability margins, and all firm/network reservations held by the seller or its affiliates that are modeled in the cases. The simultaneous transmission import capability study must reasonably reflect the transmission provider's OASIS practices and the techniques used must have been

historically available to customers. We propose to continue to use the instructions set forth in the April 14 Order.

79. Further, the April 14 Order required simultaneous transmission import capability studies to include firm point-to-point and network transmission reservations. Firm/network reservations should be subtracted from the simultaneous transmission import capability if they are not historically modeled in the power flow case. In all cases, sellers are required to provide documentation of the firm/network reservations.

80. We expect control area operators with market-based rate authority to provide simultaneous transmission import capability studies in a timely manner, consistent with the methodology described in the April 14 Order, for their control area and directly interconnected first-tier control areas in response to requests by sellers seeking market-based rate authority.[76] This includes all the required data, documentation and workpapers to support the study.

81. We also propose to reaffirm certain aspects of an approximation explained in Appendix E of the April 14 Order. The April 14 Order allows directly interconnected first-tier control areas (to the market being studied) to be considered when conducting the study. However, it does not allow control areas that are second-tier to the control area being studied to be considered.

[76] July 8 Order, 108 FERC ¶ 61,026 at P 124.

82. We propose to specify how the calculation of a seller's pro rata share of simultaneous transmission import capability should be performed. When studying its first-tier control area, the seller should allocate imports (after taking into account firm reservations by attributing them to the holders of the reservations including those applicable to the seller) pro rata between the seller and its competitors based on uncommitted capacity. We seek comments on this proposal.

j. Procedural Issues

83. The Commission notes that Order No. 662[77] issued June 21, 2005, addressed concerns that CEII claims in market-based rate filings are overbroad. In response to commenters' concerns that intervenors should have sufficient time to respond to market-based rate filings for which CEII is claimed, 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. The Commission encouraged the parties in cases in which CEII is filed to promptly negotiate a protective order in the proceeding 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 seeks comments on whether CEII designations remain a concern since issuance of that rule.

[77] Critical Energy Infrastructure Information, Order No. 662, 70 FR 37031 (June 28, 2005), FERC Stats. & Regs. ¶ 31,189 (June 21, 2005).

The Commission also seeks 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. If the Commission were to establish a longer period for submitting comments in these cases, what would be an appropriate comment period?

B. Vertical Market Power

84. The Commission historically has considered transmission market power and other barriers to entry as two separate parts of the four-prong market-based rate analysis. However, as discussed below, the examination of a seller's ability to engage in transmission market power and a seller's ability to exclude competitors from the market by erecting other barriers to entry through the control of inputs to electric power production both involve the evaluation of potential vertical market power. On this basis, in this NOPR the Commission proposes to reformulate its market-based rate analysis to consider issues relating to transmission market power and other barriers to entry under the heading "vertical market power." This proposal is intended primarily to alter the way in which we characterize these issues, rather than changing the fundamental nature of the analyses that we perform.

1. Current Policy

a. Transmission

85. To the extent that a market-based rate seller, or any of its affiliates, owns, operates, or controls transmission facilities, the Commission has required the seller to

have an OATT on file before granting market-based rate authorization. The OATT was implemented in 1996 when the Commission issued Order No. 888 to remedy undue discrimination or preference in access to the monopoly owned transmission grid. Having a Commission approved-OATT on file satisfies the Commission's concerns with regard to transmission market power. In addressing our transmission market power concerns, a seller, including its affiliates, that does not own, operate or control transmission facilities should make an affirmative statement that neither it, nor any of its affiliates, owns, operates or controls any transmission facilities.[78]

86. The Commission issued a Notice of Inquiry in Preventing Undue Discrimination and Preference in Transmission Services,[79] that seeks to explore whether, and if so, which, reforms are necessary to the Order No. 888 pro forma OATT and to the individual public utility OATTs, given the current state of the electric industry, the complaints of customers regarding remaining undue discrimination, and the apparent uncertainties and inconsistent application concerning various tariff provisions that have arisen since implementation of Order No. 888. The Commission is issuing a notice of proposed rulemaking in that proceeding concurrently with this NOPR.

---

[78] See, e.g., Citizens Power, 48 FERC ¶ 61,210.

[79] See Preventing Undue Discrimination and Preference in Transmission Service, 70 FR 55796 (Sept. 23,2005), FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 35,553 (2005) (OATT Reform Rulemaking).

b. Other Barriers to Entry

87. Although the principal barriers to entry can be raised through the ownership or control of transmission facilities, the Commission also evaluates barriers to entry other than transmission (other barriers to entry). In the early 1990s, the Commission considered whether a seller or its affiliates could erect other barriers to entry through ownership or control of sites for new capacity development, key inputs to generation, or the transportation of key inputs to generation.[80] The Commission has also considered other barriers to entry, such as: control of major engineering and consulting firms,[81] control of fuel supplies, ownership or control of equipment,[82] and the control of transportation or distribution of fuel supplies in the relevant markets.[83]

---

[80] See Doswell Limited Partnership, 50 FERC ¶ 61,251 at 61,758 (1990) (Doswell); Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 at 62,244-45 (1990) (Commonwealth Atlantic), cited in Entergy Services, Inc., 58 FERC ¶ 61,234 at n.85 (1992) (Entergy MBR I).

[81] See Wallkill Generating Company, L.P. (Wallkill), 56 FERC ¶ 61,067 (1991).

[82] See Louisville Gas and Electric Company, 62 FERC ¶ 61,016 at 61,147 (1993) (LG&E); Entergy MBR I, 58 FERC at 61,759; Pacific Gas and Electric Company, 53 FERC ¶ 61,145 at 61,505 (1990).

[83] In Enron Power Marketing, Inc., 65 FERC ¶ 61,305 at 62,405 (1993), order on clarification and reh'g, 66 FERC ¶ 61,244 (1994), the Commission determined that a power marketer may be affiliated with an interstate natural gas pipeline because, under the Commission's requirements, such pipelines must offer open-access services on a non-discriminatory basis. See also Vantus Energy Corporation, 73 FERC ¶ 61,099 at 61,316 (1995). In Idaho Power Company, 110 FERC ¶ 61,219 at 61,816 (2005), the Commission considered a utility's ownership and control of rail cars to transport coal in its evaluation of the other barriers to entry prong and held that there are many other companies from which rail cars may be leased, and that the total number of cars that the

(continued)

88. In particular, the Commission considered such things as a power producer's ownership of building sites and its affiliation with or ownership of interstate natural gas pipelines, engineering and construction firms, or local natural gas distribution systems. For example, in Wallkill, the Commission determined that affiliation with a major engineering and construction firm could not be used to erect barriers to entry because there were a large number of such firms operating on a national basis. Further, in LG&E, the Commission found that although LG&E did not own facilities used to transport natural gas, its affiliate owned gas lines and gas storage facilities. In light of this, the Commission stated that should LG&E or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for gas services to a potential electric competitor, the electric competitor could file a complaint with the Commission. The Commission has made similar findings in subsequent cases where a seller or its affiliates own or control any natural gas intrastate facilities or distribution facilities, stating that should such seller or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for fuel or services to a potential electric competitor in bulk power markets, then the competitor may file a complaint with the Commission that could result in the suspension of the seller's authority to sell power at market-based rates. The Commission has stated it will treat such denials, delays, or requirement of unreasonable terms, conditions or rates

---

utility could be considered to control (less than 200) was insignificant relative to the total number of such cars.

for gas service in the same manner as complaints by an electric competitor that an entity has refused to transmit electricity.[84]

2. <u>Proposal</u>

89. As discussed above, the Commission proposes to replace its 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, we propose that issues relating to whether the seller and its affiliates lack 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.

90. Regarding transmission issues, the current policy is that having a Commission-approved OATT on file is sufficient to mitigate transmission market power. However, the Commission has also recognized that Order No. 888 did not eliminate all potential to engage in undue discrimination and preference in the provision of transmission service.[85]

---

[84] <u>LG&E</u>, 62 FERC ¶ 61,016 at 61,148.

[85] 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]…" <u>Regional Transmission Organizations</u>, Order No. 2000, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,105 (1999), <u>order on reh'g</u>, Order No. 2000-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), <u>aff'd sub nom</u>. <u>Public Utility District No. 1 of Snohomish County, Washington v. FERC</u>, 272 F.3d 607 (D.C. Cir. 2001).

For this and other reasons, the Commission has initiated a Notice of Inquiry to address potential reforms to the current OATT.[86] We believe that any concerns regarding the adequacy of the OATT should be addressed in that proceeding. We therefore will propose to continue to find that a Commission-approved OATT, as modified as a result of the OATT Reform Rulemaking, will adequately mitigate transmission market power.

91. Nevertheless, the finding that an OATT adequately mitigates transmission market power rests on the assumption that individual applicants 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 another remedy the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[87] There may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement, merit revocation or limitation of market-based rate authority. 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 specific facts relating to the OATT violation and the entity's market-based rate authority. The Commission proposes that, if it determines, as a result of a significant OATT violation, that the market-based rate

[86] See Preventing Undue Discrimination and Preference in Transmission Service, 70 FR 55796 (Sept. 23, 2005), FERC Stats. & Regs., Proposed Regulations ¶ 35,553 (2005) (OATT Reform Rulemaking). A notice of proposed rulemaking is being issued in that proceeding concurrently with this NOPR.

[87] See, e.g., The Washington Water Power Company, 83 FERC ¶ 61,282 (1998).

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 market on the effective date of revocation of the transmission provider's market-based rate authority. We remind sellers that they must abide by the provisions of the OATT if they do not want an adverse impact on their ability to charge market-based rates.

92. The Commission also proposes to continue considering a seller's ability to erect other barriers to entry, but to do so as part of the vertical market power analysis. We propose that, in order for a seller to demonstrate that it satisfies our vertical market power concerns, with respect to other barriers to entry, it must demonstrate that it and its affiliates cannot erect other barriers to entry. In this regard, we propose 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 and distribution of inputs to electric power production; and control of sites for new capacity development in the relevant market. We also propose 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.

93. In addition, the Commission proposes 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 seeks comments on this proposal. The Commission proposes 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. The Commission also clarifies that applicants need not address interstate transportation of natural gas supplies because such transportation is regulated by this Commission.[88] Our open access regulations adequately prevent sellers from withholding interstate pipeline capacity. Interstate pipelines are required to sell available capacity at the approved maximum rates. 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, Congress has found the natural gas market competitive.[89]

94. Several commenters have suggested that a transmission planning and expansion process can ameliorate vertical market power. The Commission is seeking comments on the issues of transmission planning and expansion in the notice of proposed rulemaking in the OATT Reform Rulemaking that is being issued concurrently with this NOPR. We

---

[88] 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).

[89] Natural Gas Wellhead Decontrol Act of 1989, Pub.L. No. 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).

seek comment on whether these planning and expansion efforts under the OATT Reform Rulemaking will address commenters' concerns here.

95. The Commission seeks comment on whether 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. We also seek 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.

C. Affiliate Abuse

96. The fourth prong of the Commission's current market-based rate analysis examines whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.[90] As the Commission has explained, "[t]he Commission's concern with the potential for affiliate abuse is that a utility with a monopoly franchise may have an economic incentive to exercise market power through its affiliate dealings."[91] The Commission stated that potential abuses include such

[90] See Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 at 62,245 (1990) (discussing potential for reciprocal dealing if a buyer agrees to pay more for power from a seller in return for that seller (or its affiliates) paying more for power from the buyer (or its affiliates)).

[91] Edgar, 55 FERC ¶ 61,382 at 62,167 n.56. See also TECO Power Services Corp. and Tampa Electric Co., 52 FERC ¶ 61,191 at 61,697 n.41 (1990) ("The Commission has determined that self-dealing may arise in transactions between affiliates

(continued)

practices as affiliates selling products to a utility with a franchised service territory (franchised public utility) at excessive prices, or a franchised public utility providing inputs to an affiliate at preferentially low prices. Both of these practices are examples of market power that is exercised to the disadvantage of captive customers. The Commission also has explained that there may be a potential for affiliate abuse through means such as the pricing of non-power goods and services or the sharing of market information.

97. The Commission in the past has used two means to ensure that affiliate abuse does not occur: restrictions on sales between a franchised public utility and its affiliates, and requiring a code of conduct that governs the relationship between franchised public utilities and their affiliates.

1. Power Sales Restrictions

a. Current Policy

98. The Commission currently prohibits power sales at market-based rates between a franchised public utility and its affiliates without first receiving authorization of the transaction under section 205 of the FPA.[92] In order to be granted market-based rate authorization, a franchised public utility and all of its affiliates must include such a

---

because affiliates have incentives to offer terms to one another which are more favorable than those available to other market participants.").

[92] Aquila, Inc., 101 FERC ¶ 61,331 (2002).

prohibition in their market-based rate tariffs unless the Commission has otherwise authorized the seller to transact with its affiliates.

99. The Commission has stated its concern that a franchised public utility and an affiliate may be able to transact in ways that transfer benefits from the captive customers of the franchised public utility to the affiliate and its shareholders.[93] Where a franchised public utility makes a power sale to an affiliate, the Commission is concerned that such a sale could be made at a rate that is too low, in effect, transferring the difference between the market price and the lower rate from captive customers to the "non-regulated" affiliated entity. Where an entity makes power sales to an affiliated franchised public utility, the concern is that such sales not be made at a rate that is too high, which would give an undue profit to the affiliated entity at the expense of the franchised public utility's captive customers. The Commission has found that a transaction between two non-traditional utility affiliates (such as power marketers, EWGs, or QFs) does not raise the same concern about cross subsidization because neither has a franchised service territory and therefore has no captive customers. As the Commission has explained, no matter how sales are conducted between non-traditional affiliates, profits or losses ultimately affect only the shareholders.[94]

[93] See, e.g., Heartland Energy Services Inc., 68 FERC ¶ 61,223 at 62,062 (1994) (Heartland).

[94] FirstEnergy Generation Corporation, 94 FERC ¶ 61,177 (2001); USGen Power Services, L.P., 73 FERC ¶ 61,302 at 61,846 (1995).

100. In determining whether to allow power sales affiliate transactions, the Commission, over time, has adopted several methods, all of which have focused on ensuring that captive customers are adequately protected against affiliate abuse. We discuss these below.

101. In Edgar, the Commission described 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.[95] The Commission stated that when an entity presents evidence regarding a competitive solicitation, the Commission requires assurance that: (1) a competitive solicitation process was designed and implemented without undue preference for an affiliate; (2) the analysis of bids did not favor affiliates, particularly with respect to non-price factors; and (3) the affiliate was selected based on some reasonable combination of price and non-price factors.[96]

[95] Edgar, 55 FERC ¶ 61,382 at 62,168-69.

[96] Id. at 62,168. A seller with market-based rate authority would not necessarily be required to make a separate affirmative showing of no market power in order to fulfill the Edgar standards and receive authority to engage in an affiliate transaction.

102. In subsequent cases, the Commission expanded on the competitive solicitation prong of Edgar and has stated that it must evaluate the bidding process and determine that, based on the evidence, a proposed power sale between affiliates is the result of direct head-to-head competition.[97]

103. The Commission has provided guidelines as to how the Commission will evaluate whether a competitive solicitation process satisfies the Edgar criteria. The underlying principle when evaluating a competitive solicitation process under the Edgar criteria is that no affiliate should receive undue preference during any stage of the process.

104. In Allegheny, the Commission stated that the following four guidelines will help the Commission determine if a competitive solicitation process satisfies that underlying principle: it is transparent; products are well defined; bids are evaluated comparably with no advantage to affiliates; and it is designed and evaluated by an independent entity.[98] The Allegheny guidelines serve as one example of evidence that a competitive solicitation has resulted in just and reasonable rates; they do not constitute the only way

[97] See, e.g., Rockland Electric Company, 102 FERC ¶ 61,097 (2003); Connecticut Light & Power Company and Western Massachusetts Electric Company, 90 FERC ¶ 61,195 at 61,633-34 (2000); Aquila Energy Marketing Corp., 87 FERC ¶ 61,217 at 61,857-58 (1999); MEP Pleasant Hill, LLC, 88 FERC ¶ 61,027 at 61,059-60 (1999); Edgar, 55 FERC ¶ 61,382 at 62,167-69.

[98] See, e.g., Allegheny Energy Supply Company, LLC, 108 FERC ¶ 61,082 (2004) (Allegheny); Rockland Electric Company, 102 FERC ¶ 61,097 (2003); Conectiv Energy Supply, Inc., 91 FERC ¶ 61,076 (2000).

in which an applicant could demonstrate that a competitive solicitation was not unduly discriminatory.

105. The Commission has granted blanket authorization to make power sales to affiliates pursuant to a market-based rate tariff subject to certain conditions. For this blanket authorization, the Commission has required that sales of power by a franchised public utility to an affiliate be made at a rate no lower than the rate charged to non-affiliates; the utility offering to sell power to an affiliate must make the same offer, at the same time, to non-affiliated entities; and the utility must post simultaneously the actual price charged to its affiliate for all transactions.[99] These provisions were originally included as part of Detroit Edison's cost-based rate tariff in response to a request by Detroit Edison to sell power to its affiliated power marketer at negotiated rates subject to a cost-based price cap. However, the Commission's practice has been to allow such a provision in other sellers' market-based rate tariffs. Utilities that request this blanket authorization have been required to include those conditions in their market-based rate tariffs.[100]

106. The Commission also has authorized sales when a "non-regulated" affiliate seeks to sell power to an affiliated franchised public utility where sufficient pricing safeguards

[99] Detroit Edison Co., 80 FERC ¶ 61,348 at 62,198 (1997).

[100] See, e.g., Alliant Services Company, 85 FERC ¶ 61,344 at 62,335 (1998); Tucson Electric Power Company, 82 FERC ¶ 61,141 at 61,525 (1998).

were in place to ensure that there was no room for manipulation.[101] In Advanced Resources, the Commission found adequate a plan where the power marketer sold energy to its affiliated franchised public utility at the lowest price paid by the franchised public utility to a non-affiliate under certain standard supplier agreements. Specifically, the Commission granted authorization because the price in these standard supplier agreements was equal to the average price of power sold to the franchised public utility through the PJM power exchange. Because the price of the franchised public utility's purchases from the power marketer was set equal to the price of the franchised public utility's purchases from PJM, the Commission concluded there was no room for manipulation.

107. The Commission also has allowed sales between affiliates pursuant to a market-based rate tariff without imposing any price or transaction conditions where there were no captive wholesale or retail customers or where captive customers were adequately protected from affiliate abuse.[102] In these cases, the Commission found that captive

---

[101] See, e.g., GPU Advanced Resources, Inc., 81 FERC ¶ 61,335 (1997) (Advanced Resources); FirstEnergy Trading & Power Marketing, Inc., 84 FERC ¶ 61,214 at 62,037-38, reh'g denied, 85 FERC ¶ 61, 311 (1998) (rejecting tariffs without prejudice to the applicants submitting alternative proposals that delineate the nature of the transactions to be undertaken and demonstrate that any proposed safeguards mitigate the potential for affiliate abuse).

[102] See, e.g., Consumers Energy Company, 94 FERC ¶ 61,180 (2001) (finding there are adequate safeguards including Consumer Energy disallowing revenues for sales to CMS Marketing to be factored into any rate calculations for wholesale customers, existence of retail rate freeze, and phase in of retail choice); FirstEnergy Corp., 94 FERC

(continued)

customers were protected through fixed rate contracts, retail rate freezes, retail access, and an inability for the captive ratepayer to be harmed through fuel adjustment clauses. The Commission also has found that tying the price of an affiliate transaction to an established, relevant market price or index mitigates affiliate abuse concerns.[103]

b. Proposal

108. We remain concerned about the potential adverse impact that affiliate power sales transactions may have on captive customers[104] and propose to continue our policy of reviewing affiliate transactions under section 205 of the FPA. Although we have traditionally identified affiliate abuse as the fourth prong of our test for market-based rate

---

¶ 61,182 at 61,630 (2001) (finding of adequate safeguards based on FirstEnergy's commitment to hold wholesale customers harmless from changes in cost, a retail rate freeze in Ohio, and caps on retail rates in Pennsylvania); Exelon Generation Company, L.L.C., 93 FERC ¶ 61,140 at 61,425 (2000), reh'g denied, 95 FERC ¶ 61,309 (2001) (finding there are adequate safeguards including retail access, rate freezes, rate caps, and other mechanisms).

[103] Brownsville Power I, L.L.C., 111 FERC ¶ 61,398 at P 10 (2005) (Brownsville); See also FirstEnergy Trading Servs., Inc., 88 FERC ¶ 61,067 at 61,156 (1999) (FirstEnergy Trading); Union Light, Heat, and Power Co., 110 FERC ¶ 61,212 at P16 (2005) (affirming that use of Midwest ISO Day 2 market prices meets the Edgar test and mitigates concerns regarding transactions between affiliates); Idaho Power Company, 95 FERC ¶ 61,147 (2001) (accepting use of the Dow Jones Mid-Columbia Index and the Dow Jones Palo Verde Index for affiliate sales); Pinnacle West Capital Corporation, 91 FERC ¶ 61,290 (2000) (allowing use of the lesser of the Palo Verde Index and system incremental cost as a cap on the price for sales between affiliates); DPL Energy, Inc., 90 FERC ¶ 61,200 (2000) (affirming that use of the "into Cinergy" index price as a price cap for its power sales to Dayton P&L mitigates affiliate abuse concerns); Ameren Services Company, 86 FERC 61,212 (1999) (accepting use of "into Cinergy" for sales between affiliates).

[104] See Edgar, 55 FERC ¶ 61,382 at 62,167.

authority, in practice this prong is not only evaluated at the time an application is filed, but rather is satisified on an ongoing basis through the requirement that sellers obtain prior approval, under the foregoing standards, for affiliate power sales. To reflect and codify this practice, we propose to discontinue referring to affiliate abuse as a separate "prong" of our analysis and instead we propose to codify in our regulations at 18 C.F.R 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 provisions.[105] Thus, we will 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. However, we note that a seller seeking to obtain or retain market-based rate authority will continue to be obligated to provide a detailed description of its corporate structure so that we can be assured that our standards are being applied correctly. In particular, applicants with franchised service territories will be required to make a showing regarding whether they serve customers

---

[105] With regard to reciprocal dealing, we believe that any concerns as to a seller's ability to engage in reciprocal dealing are addressed by the affiliate abuse provisions we propose to include in the Commission's regulations as well as the Commission's final rule prohibiting energy market manipulation. See Prohibition of Energy Market Manipulation, Order No. 670, 71 FR 4244 (January 26, 2006), FERC Stats. & Regs. ¶ 31,202 (2006), order on reh'g, Order No. 670-A, 114 FERC ¶ 61,300 (2006).

and to identify all non-regulated power sales affiliates, such as affiliated marketers and generators.[106]

109. Consistent with the foregoing, we propose to amend the Commission's regulations to include a provision expressly prohibiting power sales between a franchised public utility and any of its non-regulated affiliates without first receiving authorization of the transaction under section 205 of the FPA. Further, we propose that, as a condition of receiving market-based rate authority, sellers must adopt the MBR tariff (included as Appendix A to this NOPR) which includes a provision requiring the seller to comply with, among other things, the affiliate provisions in the regulations. We note that failure to satisfy the conditions set forth in the affiliate provisions will constitute a tariff violation. We seek comments on this proposal**.**

110. Sellers seeking authorization to engage in affiliate transactions will continue to be obligated to provide evidence to support a determination as to whether there are captive customers that would trigger the application of our standards for affiliate power sales.[107] If the Commission finds, based on the evidence provided by the seller, that the seller has no captive customers, the affiliate provisions in the regulations would not apply.

---

[106] In this regard, the Commission protects captive customers by ensuring that wholesale rates are just and reasonable.

[107] Sellers that have already received authorization to make sales to affiliates would retain that authorization unless the Commission institutes a section 206 investigation to examine whether the seller's current circumstances continue to satisfy our affiliate abuse concerns and subsequently revokes such authorization.

However, if the record does not support a finding of no captive customers, the seller must abide by all affiliate restrictions contained in the regulations in order to obtain and retain market-based rate authority. In the Commission's Final Rule on transactions subject to section 203, the Commission defined the term "captive customers" to mean "any wholesale or retail electric energy customers served under cost-based regulation."[108] We seek comment on whether the same definition should be used for purposes of this rule.

111. We propose to continue our past approach for determining what types of affiliate transactions are permissible and the criteria that should be used to make those decisions. When affiliates participate in a competitive solicitation process, application of the Allegheny criteria would constitute safe harbor criteria that the affiliate abuse condition is satisfied in a transaction between a franchised public utility and its affiliate. The Commission will consider competitive solicitations, on a case-by-case basis. However, we emphasize that using a competitive solicitation is not the only way an affiliate transaction can address our concerns that the transaction does not pose affiliate abuse concerns.

112. In Edgar, two alternatives to competitive solicitation evidence were found to be acceptable evidence of a market price. These alternatives included prices non-affiliates

[108] Transactions Subject to FPA section 203, Order No. 669-A, 71 FR 28422 (May 16, 2006), FERC Stats. & Regs. ¶ 31,097 (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, 096 (2006).

are willing to pay for similar service and benchmark evidence. However, Edgar also noted the difficulty of finding such truly comparable alternative evidence.[109] This difficulty in finding adequate comparable evidence increases the likelihood that applications submitted with such evidence could raise issues of material fact and thus could be set for hearing.

113. We continue 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 (i.e., is a relevant index).[110] The Commission has stated its belief 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.[111]

114. Although the Commission has found in the past that certain non-RTO price indices are acceptable indicators of market prices, we recognize that price indices at thinly traded points can be subject to manipulation and are otherwise not good measures of market

---

[109] See Edgar, 55 FERC ¶ 61,382 at 62,169.

[110] Brownsville, 111 FERC ¶ 61,398 at P10. See also Portland General Elec. Co., 96 FERC ¶ 61,093 at 61,378 (2001); FirstEnergy Trading, 88 FERC ¶ 61,067 at 61,156 (1999).

[111] April 14 Order, 107 FERC ¶ 61,018 at P 189.

prices, as discussed in the Price Index Policy Statement[112] and November 19 Price Index Order.[113] Accordingly, we propose 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 for eligibility for use in jurisdictional tariffs.[114] The requirements include the criteria found in the Price Index Policy Statement, including but not limited to[115] reporting of prices by those not involved in trading, and a process for resolving reporting errors, as well as those specific to jurisdictional tariffs: (1) providing the volume and number of transaction data on which the index value is based (or clearly indicating when no such data is available); (2) confirming that the Commission can have access to relevant data in the event of an investigation of possible false price reporting or manipulation; and (3) establishing minimum criteria to determine whether there is adequate liquidity for daily, weekly, and monthly electricity indices.

---

[112] Policy Statement On Natural Gas And Electric Price Indices 104 FERC ¶ 61,121 (2003) (Price Index Policy Statement).

[113] Order Regarding Future Monitoring Of Voluntary Price Formation, Use Of Price Indices In Jurisdictional Tariffs, And Closing Certain Tariff Docket 109 FERC ¶ 61, 184 (2004) (November 19 Price Index Order).

[114] November 19 Price Index Order, 109 FERC ¶ 61,184 at P 40-69.

[115] Price Index Policy Statement, 104 FERC ¶ 61,121 at P 34.

115. The Commission seeks comment on whether evidence other than competitive solicitations, RTO price or non-RTO price indices, or benchmarks described above, should be accepted in an application for authority to engage in affiliate power sales.

116. With regard to merging companies the Commission has stated that for the purposes of affiliate abuse, merging companies will be considered affiliates under the market-based rate tariff while their merger is pending.[116] We seek comments regarding at what point the Commission should consider two non-affiliates as merging partners: the date the merger is announced, the date the section 203 application is filed with the Commission, or another time? The Commission proposes to use the date a merger is announced as the triggering event, but we seek comment on this issue.

117. The Commission also proposes that entities that engage in energy/asset management of generation on behalf of a franchised public utility be treated as affiliates of that franchised public utility in a manner similar to that of non-regulated affiliates and be subject to the affiliate provisions we propose herein. The Commission also proposes that entities that engage in energy/asset management of generation on behalf of non-

[116] 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.").

regulated affiliates of a franchised public utility be treated in a similar manner as the non-regulated affiliates. We seek comment on this proposal.

118. The Commission currently requires that sales made under market-based rate tariffs, including those made to affiliates, be reported in an EQR.[117] The Commission affirms that its role with regard to market-based rates, and specifically affiliate transactions, will be to either grant or deny authorization to make affiliate sales. Additionally, the Commission reiterates that, once authorized, all such sales should be reported in an EQR.

119. Although, at one time, the Commission's policy was to require certain market-based rate sellers to file their long-term market-based rate power sales service agreements with the Commission,[118] since the issuance of Order No. 2001, the Commission's policy has been to require that such agreements not be filed with the Commission. Notwithstanding this policy, the Commission on occasion may have accepted long-term service agreements for filing. At this time, the Commissionreaffirms that long-term affiliate sales contracts under the seller's market-based rate tariff that are authorized by

[117] Revised Public Utility Filing Requirements, Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 31,127 (2002).

[118] See Southern Company Services, Inc., 99 FERC ¶ 61,103 (2002).

the Commission shall not be filed with the Commission.[119] However, the seller must make a section 205 filing with the Commission to obtain authorization to engage in an affiliate transaction, and may not engage in such transaction without first receiving such authorization.

2. Market-Based Rate Code of Conduct For Affiliate Transactions Involving Power Sales and Brokering, Non-Power Goods and Services and Information Sharing

a. Current Policy

120. The Commission requires affiliates of franchised public utilities that request market-based rate authority to submit a market-based rate code of conduct to govern the relationship between the franchised public utility and its affiliates. Historically, the purpose of the market-based rate code of conduct[120] has been to safeguard against

---

[119] 18 CFR § 35.1(g) (2005) ("[A]ny market-based rate agreement pursuant to a tariff shall not be filed with the Commission").

[120] The market-based rate code of conduct has at times been confused with the Commission's Standards of Conduct. The electric Standards of Conduct, originally issued in Order No. 889 et seq., were established to govern the relationship between a public utility's transmission function and its wholesale merchant function (including affiliated power marketers) to ensure that all transmission customers have equal access to transmission information. See Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 FR 21,737 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 FR 12,484 (1997), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,049 (1997), reh'g denied, Order No. 889-B, 81 FERC ¶ 61,253 (1997), order on reh'g, Order No. 889-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000). The Standards of Conduct were recently updated by the Commission. See Standards of Conduct for Transmission Providers, Order No. 2004, 68 FR 69134

(continued)

affiliate abuse by protecting against the possible diversion of benefits or profits from franchised public utilities (i.e., traditional public utilities with captive ratepayers) to an affiliated entity for the benefit of shareholders. Just as the Commission has expressed concern about the potential for affiliate abuse in connection with power sales between affiliates, it also has recognized that there may be a potential for affiliate abuse through other means, such as the pricing of non-power goods and services or the sharing of market information between affiliates.[121] The market-based rate code of conduct was designed to address these concerns. The Commission has waived the market-based rate code of conduct requirement in cases where there are no captive customers, and thus no potential for affiliate abuse, or where the Commission finds that such customers are adequately protected against affiliate abuse.[122] In such cases, however, the Commission

---

(Dec. 11, 2003), III FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 31,155 (Nov. 25, 2003), order on reh'g, Order No. 2004-A, 69 FR 23,562, (Apr. 29, 2004), III FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 31,161 (April 16, 2004), order on reh'g, Order No. 2004-B, 69 FR 48,371 (Aug. 10, 2004), III FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 31,166 (Aug. 2, 2004), order on reh'g, Order No. 2004-C, 70 FR 284 (Jan 4., 2005), III FERC Stats. & Regs., Regulations Preambles January 2001-December 2005 ¶ 31,172 (Dec. 21, 2004), order on reh'g, Order No. 2004-D, 110 FERC ¶ 61,320 (March 23, 2005), appeal docketed sub nom., Natural Gas Fuel Supply Corp. v. FERC, No. 04-1183 (D.C. Circuit).

[121] See, e.g., Potomac Electric Power Company, 93 FERC ¶ 61,240 at 61,782 (2000); Heartland, 68 FERC ¶ 61,223 at 62,062-63.

[122] See, e.g., CMS Marketing, Services and Trading Co., 95 FERC ¶ 61,308 at 62,051 (2001) (granting request for cancellation of code of conduct where wholesale contracts, as amended, "cannot be used as a vehicle for cross-subsidization of affiliate

(continued)

directed the utilities to notify the Commission should they obtain captive customers in the future and expressly reserved the right to reimpose the market-based rate code of conduct requirement. In the Order No. 2004 Standards of Conduct rulemaking proceeding, the Commission solicited comment on whether to reform the market-based rate code of conduct but determined that such reform should take place in a separate proceeding.[123]

121. The market-based rate code of conduct requirements have evolved through market-based rate orders.[124] Beginning with orders issued in 1999, the Commission informed sellers that if an applicant submitted a market-based rate code of conduct that was inconsistent with the market-based rate code of conduct attached to those orders, the

---

power sales or sales of non-power goods and services"); Alcoa, Inc., 88 FERC ¶ 61,045 at 61,119 (1999) (waiving code of conduct requirement where there were no captive customers); Green Power Partners 1 LLC, 88 FERC ¶ 61,005 at 61,010-11 (1999) (waiving code of conduct requirement where there are no captive wholesale customers and retail customers may choose alternative power suppliers under retail access program).

[123] Order No. 2004, at 30,853. The following entities submitted comments in the Standards of Conduct rulemaking proceeding in Docket No. RM01-10-000 relating to the concept of codifying the code of conduct: Cinergy (codification not needed); Entergy (if codified, the code of conduct should reflect established codes); NEPOOL Industrial Customer Coalition (codification needed); LG&E Energy Corporation (separate code of conduct policy issues should be treated in a separate rulemaking); PanCanadian Energy Services, Inc. (codification unnecessary).

[124] Seminal early Commission decisions discussing the purposes of the code of conduct requirements include Heartland and LG&E Power Marketing, Inc., 68 FERC ¶ 61,247 at 62,121-24 (1994).

Commission would reject it and designate the attachment as the applicable code.[125] The Commission's market-based rate code of conduct provisions state:

> STATEMENT OF POLICY AND CODE OF CONDUCT
>
> WITH RESPECT TO THE RELATIONSHIP BETWEEN
>
> [POWER MARKETER/ POWER PRODUCER] AND [PUBLIC UTILITY]
>
> Marketing of Power
>
> 1. To the maximum extent practical, the employees of [Power Marketer/Power Producer] will operate separately from the employees of [Public Utility].
>
> 2. All market information shared between [Public Utility] and [Power Marketer/Power Producer] will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.
>
> 3. Sales of any non-power goods or services by [Public Utility], including sales made through its affiliated EWGs or QFs, to [Power Marketer/Power Producer] will be at the higher of cost or market price.
>
> 4. Sales of any non-power goods or services by the [Power Marketer/ Power Producer] to [Public Utility] will not be at a price above market.
>
> Brokering of Power
>
> To the extent [Power Marketer/Power Producer] seeks to broker power for [Public Utility]:

[125] See, e.g., Northeast Utilities Service Company, 87 FERC ¶ 61,063 (1999) (requiring market-based rate applicants to submit codes of conduct consistent with an attached code of conduct and imposing the attached code in the event of inconsistency).

5. [Power Marketer/Power Producer] will offer [Public Utility's] power first.

6. The arrangement between [Power Marketer/Power Producer] and [Public Utility] is non-exclusive.

7. [Power Marketer/Power Producer] will not accept any fees in conjunction with any Brokering services it performs for [Public Utility].

122. The Commission has also accepted the inclusion of an additional provision to govern brokering activities where a franchised public utility brokers for one of its affiliates.[126]

123. Numerous significant changes have taken place in the electric industry relevant to the market-based rate code of conduct requirement since the Commission approved the first market-based rate codes of conduct in the mid-1990s. The Commission has required open access transmission service in Order No. 888; there has been an increase in the number of power marketers and power producers authorized to transact under market-based rates, as well as an increased market for available transmission capacity, an increased number of power transactions, and new and different uses for the transmission

[126] See MEP Investments, LLC, 87 FERC ¶ 61,209 at 61,828 (1999) ("CP&L has taken the brokering rules established by the Commission for the opposite situation (when the marketer is brokering for the utility), and modified them to apply to its situation. Specifically, instead of the no-fee rule when a marketer brokers for its affiliate, for brokering service CP&L provides to Monroe, CP&L will charge Monroe the higher of CP&L's costs for that service or the market rate for such services. CP&L will also market its own power first, simultaneously make public any information shared with Monroe during brokering, and post on its Internet site the actual brokering changes imposed. This addition to CP&L's code of conduct is accepted.").

grid.[127] The Commission has found that the nature of electric market participants is also changing, with the rise of power marketers and generation facilities that are affiliated with traditional regulated entities, as well as unaffiliated entities.[128]

124. There also has been an increased range of activities engaged in by asset or energy managers.[129] Although asset managers can provide valuable services and thereby benefit consumers and the marketplace, such relationships also could result in transactions harmful to captive customers. We note that, as the consequence of one Commission investigation, there was a settlement agreement pursuant to which a company's market-based rate codes of conduct were revised to expand (a) the range of affiliates to which

---

[127] Standards of Conduct for Transmission Providers, Order No. 2004, 68 FR 69134, FERC Stats. & Regs., ¶ 31,155, Regulations Preambles January 2001- December 2005.

[128] Id. As of April 1, 2006, approximately 1170 entities have market-based rate authority granted by the Commission. They include approximately 390 independent power marketers, 70 traditional utilities with market-based rate authority, 100 affiliated power marketers, 400 affiliated power producers, 180 independent power producers and 30 financial institutions.

[129] 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.)

they applied and (b) the regulation of conduct between affiliates, including the asset manager.[130]

125. While the Commission has required that entities comply with the provisions of the market-based rate code of conduct, the market-based rate code of conduct has not been codified in the Commission's regulations. Further, some applicants for market-based rate authority have requested and received variations from the market-based rate code of conduct. Such variations, while reasonable in individual circumstances, may over time become inconsistent with the Commission's goals of protecting captive customers and fostering transparent and consistent regulation of the market. Likewise, some corporate families have filed several different market-based rate codes of conduct for their affiliates while others have filed only one or have received a waiver of the market-based rate code of conduct requirement.

[130] In 2003, as part of a Settlement Agreement with the Commission, Cleco Corp. agreed to an expansion of its codes of conduct governing relations between its various affiliates that Enforcement staff alleged had participated in power sales and related conduct in violation of the Standards of Conduct and Cleco's previous codes of conduct. Cleco Corp., 104 FERC ¶ 61,125 (2003). Pursuant to the terms of the resulting settlement agreement, Cleco submitted revised codes that governed information sharing and independent functioning between Cleco's three exempt wholesale generators (with market-based rate authority), its power marketer that in essence acted as an asset manager for the three, and its captive ratepayer utility, rather than merely code provisions governing relations between, on the one hand, the captive ratepayer utility, and, on the other, the marketing and generation affiliates.

126. An example of inconsistent market-based rate codes of conduct was revealed in Commission staff's audit of Progress Energy, Inc. In that proceeding, there were eight different codes with differing provisions for different Progress affiliates.[131]

b. Proposal

127. The Commission continues to believe that a code of conduct is necessary to protect captive customers from the potential for affiliate abuse. Further, in light of the repeal of the Public Utility Holding Company Act of 1935 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, it is important that the Commission have in place restrictions to preclude transferring captive customer benefits to stockholders through a company's "non-regulated" power sales business. We therefore believe it is appropriate to condition all market-based rate authorizations, including authorizations for sellers within holding companies, on the seller abiding by a code of conduct for sales of non-power goods and services between power sales affiliates.

128. We also believe that greater uniformity and consistency in the codes of conduct is appropriate. With the experience gained over the years in approving various codes of conduct, including our standard code of conduct, we are proposing to adopt a uniform

[131] See Florida Power Corp., 111 FERC ¶ 61,243 (2005), attached staff Audit Report at 6.

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. We therefore propose to codify such affiliate provisions in section 35.39(b)-(e) of our regulations and to require that, as a condition of receiving market-based rate authority, sellers comply with these provisions. Failure to satisfy the conditions set forth in the affiliate provisions will constitute a tariff violation. This uniformity will help ensure that captive customers are protected and that affiliate provisions are applied and administered in an even-handed manner in harmony with legitimate current industry practices. We seek comment on this proposal and on whether the specific affiliate provisions proposed in this NOPR are sufficient to protect captive customers. In particular, what changes, if any, should the Commission adopt? Additionally, as previously noted, we seek comment on the definition of “captive customer.”

129. The proposed provisions are the same as those in the standard code of conduct that exists today with the following exceptions. First, the proposed regulations use the term “non-regulated” affiliates instead of power marketer/power producer to make it clear that the provisions apply to the relationship between a franchised public utility and any of its affiliates that are not regulated under cost-based regulation. This includes affiliate power marketers and affiliate power producers, such as EWGs and QFs.

130. Second, in the case of companies that are acting on behalf of and for the benefit of franchised public utilities with captive customers, the proposed affiliate provisions treat

such companies, for purposes of the affiliate provisions, as the franchised public utility. For example, if a company has been created to manage generation assets for the franchised public utility, such entity is 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.

131. 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. For example, asset managers of a non-regulated affiliate's generation assets are treated as the non-regulated affiliate with regard to, for example, the information sharing provision. We seek comment on this proposal.

132. The Commission invites comments proposing other additions, substitutions, or eliminations to the proposed affiliate provisions.

D. Mitigation

1. Current Policy

133. The Commission began accepting applications for market-based power sales in the late 1980s as a means to provide greater flexibility to transactions in emerging competitive wholesale power markets. The analysis for horizontal market power at that time was the "hub and spoke" methodology, and under that methodology most sellers received market-based rate approval. If, however, a seller failed the hub and spoke analysis for a particular market, as a general matter, no specific mitigation was imposed.

Rather, the seller could continue to sell power under existing cost-based rate schedules on file with the Commission in that area.

134. The Commission began providing greater flexibility in setting cost-based rates for coordination sales during this period as well. Historically, utilities had set the rate for coordination sales on a "split the savings" formula[132] or on the incremental cost of the units participating in the sale (plus an adder). In the late 1980s, however, the Commission began to approve a variety of "up to" rates under which the applicant could charge a rate that was anywhere between a "floor" of incremental cost and a "ceiling" of variable energy costs plus an embedded cost demand charge. Examples of this more flexible approach were the Western Systems Power Pool, Inc. agreement, under which all sellers in the Western Interconnect could transact under a common ceiling rate. The Commission also provided significant flexibility to individual sellers, such as by allowing them to cap rates at the cost of the most recently installed unit, even if that unit was a high-cost baseload unit.

135. This more flexible approach to wholesale power sales continued largely unchanged until 2001 when the Commission adopted the supply margin assessment

[132] A seller’s incremental cost (the out-of-pocket cost of producing an additional MW) is compared with a buyer’s decremental cost (the cost of not producing the last MW). The average of the incremental and decremental cost is the “split the savings” rate.

(SMA) test.[133] The SMA sought to strengthen the horizontal market power test in several significant ways, such as considering transmission capability to limit the amount of competitive supplies that could get into the relevant market. Although not imposing a cost-based rate for longer term transactions, the SMA developed a "must offer" requirement and a "split the savings" formula in the event that a seller failed the generation market power test, which was the traditional cost-based ratemaking model used for spot market energy sales.

136. In the April 14 and July 8 Orders, the Commission replaced the SMA test with two indicative screens for assessing horizontal market power, the pivotal supplier screen and the wholesale market share screen, and modified the Commission's approach to cost-based mitigation.

137. In the April 14 Order, the Commission adopted default mitigation tailored to three distinct products: (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 will be priced at an embedded cost "up-to" rate reflecting the costs of the unit(s) expected to provide the service; and (3) sales of power for one year or more will be priced at an embedded cost of service basis and each such contract will be filed with the Commission for review and approved prior to the commencement of service. The Commission determined that sellers that are found to have market power (i.e., after

---

[133] See AEP Power Marketing, Inc., 97 FERC ¶ 61,219 (2001) (SMA Order).

the Commission has ruled on the DPT analysis), or that accept a presumption of market power, may either accept the Commission's default cost-based mitigation measures or propose their own case-specific measures tailored to their particular circumstances that eliminate their ability to exercise market power, including adopting existing cost-based rates, but did not provide guidance as to which departures from the default mitigation would be approved.[134]

2. Proposal

138. We seek comment on whether the default mitigation set forth in the April 14 Order is appropriate as currently structured. In particular, certain recurring issues have arisen in implementing the cost-based mitigation and we seek comment on these issues. Specifically, we seek comment, as discussed further below, on four issues of recurring significance: (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.

a. Cost-Based Rate Methodology

139. We first seek comment on issues associated with the rate methodology for designing cost-based mitigation. There are two principal issues concerning rate methodology that have arisen in implementing the April 14 Order. The first relates to the requirement that sales of less than one week be made at incremental cost plus 10 percent.

[134] April 14 Order, 107 FERC ¶ 61,018 at P 147, 148 & n.142, 150 & n.144.

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 less than one week. We seek comment on whether to continue to apply a default rate for sales of less than one week that is tied to incremental cost plus 10 percent. Are there problems associated with using “up to” rates for shorter-term sales and, if so, what are they? Does the current approach provide utilities a disincentive to offer their power to wholesale customers in their local control area for short-term sales? Would an “up to” rate adequately mitigate market power for such sales?

140. The second rate methodology issue relates to the design of an "up to" cost-based rate. In the past, the Commission has allowed significant flexibility in designing “up to” rates. Is that flexibility still warranted? For example, there are often disputes over which units are “most likely to participate” or “could participate” in coordination sales. Should the Commission continue to allow utilities flexibility in selecting the particular units that form the basis of the “up to” rate? If not, what units should an “up to” rate be based upon, and how should that rate be calculated? Should the Commission prescribe a standard methodology that would allow an applicant to avoid a hearing on rate methodology? Would a methodology that is based on average costs (both variable and embedded) allow an applicant to avoid a hearing because it eliminates the seller’s discretion in designating particular units as “likely to participate”? Are there other approaches that would accomplish a similar objective?

141. In the April 14 and July 8 Orders, the Commission stated 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, should the Commission 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? Would the use of such agreements as a mitigation measure satisfy the just and reasonable standard of the FPA?

142. Finally, the Commission notes that if a mitigated seller is returning to existing cost-based rates, the Commission would have the obligation to consider whether those rates are sufficient for that purpose, and would have the authority to institute a proceeding under FPA section 206 to investigate their justness and reasonableness.

b. Discounting

143. A seller that has authorization to sell under an "up to" cost-based rate has an incentive to discount its sales price when the market price in the seller'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 customers.

144. The primary issue in this area is whether a seller can "selectively" discount, i.e., offer different prices to different purchasers of the same product during the same time

period. We seek 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 we do allow selective discounting, what mechanisms (reporting or otherwise), if any, are necessary to protect against undue discrimination? By contrast, if we do not allow selective discounting, should we require the utility to post discounts to ensure that they are available to all similarly situated customers?

c. Protecting Mitigated Markets

145. Under our current policy, if a seller loses market-based rate authority in its home control area, any sales in that control area must be pursuant to cost-based rates; 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 its available power to purchasers outside that control area if, for example, market prices outside its control area exceed the cost-based caps. Wholesale customers have argued that default cost-based mitigation of this kind is of little value if a mitigated seller can simply market its excess capacity at market-based rates in other control areas.[135] To address this concern, commenters have suggested that the Commission either revoke a mitigated seller's market-based rate authority in all control areas or impose some type of mitigation that protects wholesale

---

[135] See, e.g., Carolina Power and Light Company, 113 FERC ¶ 61,130 at P 16 & n.21 (2005).

customers in those areas where a seller has been found to have market power or has accepted the presumption of market power.

146. The Commission seeks comment on whether its current policy is appropriate and, if not, what further restrictions are necessary. In particular, we seek comment on the following:

a. Is it 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? Does this represent undue discrimination or otherwise constitute "withholding" in the home control area that is inconsistent with the FPA's mandate that rates be just, reasonable and not unduly discriminatory? Or, does this reflect economically efficient behavior and encourage necessary trading within and across regions, particularly in peak periods when marginal prices rise above average embedded costs?

b. Should the Commission 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, should the must offer requirement 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? For example, should there 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 is free to sell the remaining capacity at market-based rates where it has authority to do so? If we adopt such a must offer requirement, what rules should there be to define "available" capacity to avoid case-by-case disputes over this issue?

c. As an alternative, should the Commission find that any seller that has lost market-based rate authority in its home control area should not be able to sell power at market-based rates in adjacent (first tier) control areas? Would this be appropriate mitigation and easier to implement than a must offer requirement? Or, would such mitigation unnecessarily discourage trading and flexibility in markets for which the seller has been found not to have market power?

d. Sales that Sink in Unmitigated Markets

147. The Commission has stated that its role is to assure customers that sellers who are authorized to sell at market-based rates do not have market power or have adequately mitigated the potential exercise of market power.[136] Further, the Commission's recent orders accepting mitigation proposals are clear that the mitigation is to apply to sales in

---

[136] July 8 Order, 108 FERC ¶ 61,026 at P 146.

the geographic market where an applicant is found (or presumed) to have market power (mitigated market), not only sales to end users in the control area.[137] In order to put in place adequate mitigation that eliminates the ability to exercise market power and ensure that rates are just and reasonable,[138] all market-based rate sales in a mitigated market where an applicant is found or presumed to have the ability to exercise market power must be subject to mitigation approved by the Commission.

148. 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.[139] However, in MidAmerican Energy Company,[140] 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 those buyers that serve end-use customers in the mitigated market. 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. Such a limitation would not

---

[137] See Oklahoma Gas and Electric Company and OGW Energy Resources, Inc., 114 FERC ¶ 61,297 (2006), reh'g pending; Carolina Power and Light Company, 114 FERC ¶ 61,294 (2006) (CP&L); Duke Energy Trading and Marketing, L.L.C., 114 FERC ¶ 61,056 (2006).

[138] See April 14 Order at P 144, 147.

[139] The Commission has recently clarified that mitigation applies to all sales in a mitigated market. See, e.g., CP&L, 114 FERC ¶ 61,294 at P 9 (2006).

[140] 114 FERC ¶ 61,280 (2006), reh'g pending (MidAmerican).

mitigate the seller's ability to attempt to exercise market power over sales in the mitigated market and is inconsistent with our direction in the April 14 and July 8 Orders. For example, 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 applicant has been found to have market power. In particular, arguments were made that an applicant 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 we restrict mitigated applicants to selling power only to buyers serving end-use customers, [141] and has since rejected tariff language that proposes to do so.[142]

149. The Commission seeks comment on whether it should modify or revise its current policy and, if so, how. In particular, we seek comment on the following:

a. Should the Commission allow market-based rate sales by a mitigated seller within a mitigated market if those sales do not "sink" in that control area? If so, under what circumstances should the Commission allow such sales and how would the Commission ensure that such sales do indeed "sink" in an unmitigated control area? How does the Commission distinguish possible permissible sales to the border of the

---

[141] See July 8 Order, 108 FERC ¶ 61,026 at P 134.

[142] See, e.g., MidAmerican, 114 FERC ¶ 61,280 at P 33.

restricted control area from sales that are not permitted within the restricted control area?

b. Under such a policy, what opportunities, if any, are presented to “game” the mitigation? If it is determined that a mitigated seller’s sales in fact do not “sink” outside the restricted control area, what penalties should the Commission consider?

c. If the Commission retains its current policy of prohibiting all market-based rate sales by a mitigated seller in a mitigated market what effect, if any, does such a policy have on existing contractual arrangements? With regard to existing transmission rights a buyer may have in a mitigated market, how easily could existing market-based rate agreements between that buyer and the mitigated seller be amended to provide for delivery of power in an unmitigated market under the same economic terms as exists today?

E. Implementation Process

1. Current Practice

150. The Commission’s current practice is a case-by-case analysis of new applications for market-based rate authorization as well as updated market power analyses. In addition, to date the Commission has allowed sellers to propose their own individualized tariffs.

2. **Proposal**

151. The Commission proposes to put in place a structured, systematic review to assist the Commission in analyzing sellers based on a coherent and consistent set of data for relevant geographic markets. In addition, some corporate families have many subsidiaries with market-based rate authorization, each with its own separate tariff. This has led to confusion, inconsistencies between the tariffs of a single corporate family, and difficulty in coordinating changes to the tariffs. To remedy these concerns, the Commission proposes to streamline the administrative process associated with the filing and review of market-based rate updated market power analyses and to consolidate market-based rate authorizations into a single tariff.

152. The Commission proposes to continue to require sellers to submit updated market power analyses for all relevant geographic markets (default or proposed alternative markets, as discussed previously) in which they own or control generation. However, the Commission proposes to modify this filing requirement in two ways. First, the Commission proposes to establish two categories of sellers with market-based rate authorization. The first category (Category 1) 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. In addition, Category 1 sellers 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 such

facilities are limited and discrete and do not constitute an integrated grid[143]), and must present no other vertical market power issues. Rather than requiring Category 1 sellers to file a regularly scheduled triennial review, the Commission would monitor any market power concerns through the change in status reporting requirement and through ongoing monitoring by the Commission's Office of Enforcement.[144] All sellers with market-based rate authority are required to make a filing with the Commission regarding any change in status that reflects a departure from the characteristics that the Commission relied upon in granting market-based rate authority. Failure to timely file a change in status report would constitute a violation of the Commission's regulations and the seller's MBR tariff.[145] A seller would be subject to disgorgement of profits and/or civil penalties from the date on which the tariff violation occurred. Such seller may also be subject to suspension or revocation of its authority to sell at market-based rates (or other appropriate non-monetary remedies). In addition, the Commission would retain the right to initiate a section 206 proceeding if circumstances warranted. A seller that no longer satisfies the Category 1 criteria would be required to submit a change in status notification and would be subject to the updated market power analysis filing required of Category 2 sellers.

---

[143] See, e.g., Black Creek Hydro, Inc., 77 FERC ¶ 61,232 (1996).

[144] Order No. 652, FERC Stats. & Regs., ¶ 31,175.

[145] Id. at P 113.

153. The second category (Category 2) would include all sellers that do not qualify for Category 1. Category 2 sellers, in addition to the requirement to file change in status reports, would be required to file regularly scheduled triennial reviews. Category 2 sellers are the larger sellers with 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 Category 1 sellers.

154. To ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposes to require each seller to file updated market power analyses for its relevant geographic markets (default and any proposed alternative markets) 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.[146] The regional reviews would rotate by geographic region with three regions reviewed per year. Appendix B provides a schedule for the proposed regional review process. The Commission proposes to continue to make findings on an individual seller basis, but will have before it a complete picture of the uncommitted capacity and simultaneous import capability into the relevant geographic markets under review.

[146] Sellers would be deemed to be assigned to a region based on the control area in which they own or control generation. Nine regions will be examined using the regions specified in the 2004 State of the Markets Report, excluding ERCOT, as shown in the map attached as part of Appendix B. Those regions are: Northwest, California, Southwest, Midwest, SPP, Southeast, PJM, New York, and New England.

155. The Commission proposes to codify in its regulations the obligation for Category 2 sellers to timely file a triennial review. As a result, failure to timely file a triennial review would constitute a violation of the Commission's regulations and the seller's MBR tariff and could result in disgorgement of profits and/or civil penalties from the date on which the seller violated its tariff.[147] A seller may also be subject to suspension or revocation of its authority to sell at market-based rates (or other appropriate non-monetary remedies). If a seller files a timely triennial review, its market-based rate authority would continue unless the Commission institutes a section 206 proceeding because the seller fails one of the indicative screens and the Commission subsequently makes a definitive finding of market power and revokes its market-based authority, or the seller accepts the presumption of market power and adopts the default cost-based mitigation or proposes other cost-based mitigation or tailored mitigation.

156. Some corporate families own or control generation in multiple control areas and different regions. For example, a corporate family may own generation facilities on the east coast as well as in California. In this instance, the corporate family would be required to file a current triennial review for each region in which members of the corporate family sell power during the time period specified for that region. To the

---

[147] Currently, the requirement to file triennial reviews is contained in our orders, but not in the tariffs or in our regulations.

extent a new subsidiary is formed and a new request for market-based rate authority is submitted, triennial reviews will be due at the regularly scheduled time for review of the markets in the region in which the new applicant owns or controls generation. We seek comment on this proposal.

157. In addition, the Commission proposes to require that all triennial review filings 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 and listing the in-service date and nameplate and/or seasonal ratings by unit. 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 and the location of such facilities.

158. Triennial reviews should reflect the most recently available historical data from the calendar year prior to the year of filing.

159. We seek comments on the proposal to adopt these filing requirements.

F. <u>Market-Based Rate Tariff (MBR Tariff)</u>

160. Historically the Commission has not required the filing of a market-based rate tariff of general applicability. However, many sellers have submitted one or more umbrella market-based rate tariffs that set forth the conditions of market-based rate approval and the general terms applicable to all transactions, with individual transactions being negotiated through service agreements, letter confirmations, or other documentation that sets forth the rates and any individualized terms and conditions. This general practice has afforded flexibility to sellers as markets and the industry evolved and

as new products and services were sold under market-based rate tariffs. However, this flexible approach has sometimes resulted in inconsistency in the tariffs filed within the same corporate family, which can create confusion for customers and compliance problems, and it also has resulted in inconsistencies in memorializing the conditions of market-based rate approval in such tariffs.

161. As part of our effort to streamline and simplify the market-based rate program in general, while at the same time maintaining a high degree of transparency and oversight, we propose to adopt a market-based rate tariff of general applicability that all sellers authorized to sell wholesale electric power at market-based rates will be required to file as a condition of market-based rate authority.[148] The MBR tariff would require the seller to comply with the applicable provisions of the market-based rate regulations which this NOPR proposes to codify in 18 CFR Part 35, Subpart H. These provisions reflect the Commission's two decades of experience with market-based rate power sales and should serve to reduce the burden on customers of managing multiple tariffs. In addition, the seller would be required to list on the MBR tariff the docket numbers and case citations, where applicable, of the proceedings, if any, in which the seller received Commission authorization to make sales of energy between affiliates or where its market-based rate authority was otherwise restricted or limited. A copy of the proposed MBR tariff is attached as Appendix A.

[148] Order No. 614 guidelines for designating rate schedules must be observed.

162. 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 seeks comments on 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 that seller.

163. In proposing the adoption of the MBR tariff, our purpose is not to direct the terms and conditions of a particular power sale or to otherwise reduce the flexibility afforded to market-based rate sellers in fashioning the terms of individual transactions. Rather, 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. Further, 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 website and include any related provisions in individual transaction agreements. Our purpose in requiring a MBR tariff of general applicability is to ensure that the MBR tariff on file with the Commission for each seller 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 our proposed regulations, and that the rates, terms and conditions of any particular sale will be negotiated between the seller and individual purchasers. We do not

believe any useful purpose is served in having on file the commercial terms preferred by particular applicants, given that the purpose of market-based rate authorization is to provide flexibility in such terms and conditions. Furthermore, our standards for approval of market-based rates do not include a review of such individualized commercial terms and thus, such submissions are unnecessary.

164. Further, the Commission proposes that, rather than each entity having its own MBR tariff, which can result in dozens of tariffs for each corporate family with conflicting provisions, each corporate family has only one tariff on file, with all affiliates with market-based rate authority separately identified in the tariff. This will allow for better transparency with regard to what sellers each corporate family has, and a more customer-friendly tariff. The requirement to have a single MBR tariff does not mean that all members of a corporate family would be counterparties on every sale under the tariff; rather, individual transactions would continue to be consummated with individual sellers within the corporate family, as they are today.

165. We seek comments on this proposal.

166. Regarding the specifics of filing the MBR tariffs, we note that the Commission has initiated a rulemaking proceeding to require the filing of electronic tariffs.[149] We propose

[149] See Electronic Tariff Filings, Notice of Proposed Rulemaking, 69 FR 43929 (July 23, 2004), FERC Stats. & Regs., Proposed Regulations ¶ 32,575 (July 8, 2004).

that the timing of filing and format for the MBR tariffs be consistent with the requirements of the final rule issued in that proceeding.

G. Miscellaneous Issues

1. Waivers

167. Certain entities with market-based rate authority have typically been granted waiver of the Commission's Uniform System of Accounts, and thus have not been subject to specified accounting rules. For instance, Parts 41, 101, and 141 of the Commission's regulations prescribe certain informational requirements that focus on the assets that a public utility owns.[150] For market-based rate applications, the Commission has taken the position that, because a power marketer does not own any electric power generation or transmission facilities, its jurisdictional facilities would be only corporate and documentary, its costs would be determined by utilities that sell power to it, and its earnings would not be defined and regulated in terms of an authorized return on invested capital; accordingly, the Commission has granted waivers to power marketers of the requirements of these Parts. The Commission also has granted other market-based rate sellers, such as independent or affiliated power producers, waiver of the requirements of these Parts.

168. The Commission has also granted power marketers' and others' requests for blanket approval under Part 34 of the Commission's regulations for all future issuances

[150] Part 41 pertains to adjustments of accounts and reports; Part 101 contains the Uniform System of Accounts; Part 141 describes required forms and reports.

of securities and assumptions of liability, assuming that no party objects to such treatment during a notice period which the Commission provides.[151] The purpose of section 204 of the FPA, which Part 34 implements, is to ensure the financial viability of public utilities obligated to serve electric consumers. The Commission has granted 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 public service franchise providing electricity to consumers dependent upon its service.[152]

169. 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 seeks comment on the extent to which these entities should be required to follow the Uniform System of Accounts, what financial information, if any, should be reported by these entities, and how frequently it should be reported, and whether the Part 34 blanket authorizations continue to be appropriate.

---

[151] We note that the Commission's jurisdiction over issuances of securities and assumptions of liabilities under section 204 of the FPA applies only to entities that are public utilities as defined in the FPA and only where the public utilities' security issues are not regulated by a State commission (see FPA section 204(f)).

[152] See, e.g., St. Joe Minerals Corp., 21 FERC ¶ 61,323 (1982); Cliffs Electric Service Company, 32 FERC ¶ 61,372 (1985); Citizens Energy Corp., 35 FERC ¶ 61,198 (1986); Howell Gas Management Company, 40 FERC ¶ 61,336 (1987); and Nevada Sun-Peak Limited Partnership, 86 FERC ¶ 61,243 (1999).

170. The Commission announced in the April 14 Order that, where an applicant is found to have market power (or where the applicant accepts a presumption of market power), the applicant will be required to adopt some form of cost-based rates or other mitigation the applicant proposes and the Commission accepts. Under these circumstances, the Commission found that it is essential that appropriate accounting records be maintained consistent with the Commission's regulations. Accordingly, the Commission indicated it will no longer waive the otherwise applicable accounting regulations (e.g. Parts 41, 101, and 141 of the Commission's regulations).[153] Thus, the Commission would revoke the accounting waivers for a mitigated seller, and for any of its affiliates with market-based rates in the mitigated control area. Further, the Commission stated that it will not grant blanket approval for issuances of securities or assumptions of liability pursuant to Part 34 of the Commission's regulation for the mitigated seller and its affiliates.[154] In the case of any affiliates, this would entail rescission of these blanket authorizations in all geographic areas, not just the mitigated control area.

171. We note 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. Consistent with the

[153] April 14 Order, 107 FERC ¶ 61,018 at P 150.

[154] Id.

April 14 Order, any waivers previously granted in connection with those sellers' market-based rate authority are no longer applicable. We propose that such revocation of waivers become effective 60 days from the date of an order revoking such waivers in order to provide the affected utility with time to make the necessary filings with the Commission and allow for an orderly transition from selling under market-based rates to cost-based rates. We seek comment in this regard. The Commission seeks 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.

2. Foreign Sellers

172. Under existing policy, a foreign entity 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 foreign sellers, the Commission allows a modified approach to the four prongs.

173. With regard to generation market power, should a foreign seller or any of its affiliates own or control any generation in the United States, or should one of its first-tier markets include a United States market, it should perform the market power screens in the appropriate control area(s).

174. With regard to transmission market power, the Commission requires a foreign seller 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 competitors of the foreign seller to reach United States markets.[155] However, if foreign transmission facilities meet the criteria for waiver of Order No. 888, such a demonstration would not be required.[156]

175. For purposes of market-based rate authorization, 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.[157]

176. Regarding other potential barriers to entry, a foreign seller should 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.

177. Finally, regarding affiliate abuse, the Commission typically requires a power marketer with market-based rate authorization to file for approval under section 205 of the FPA before selling power to or purchasing power from any utility affiliate. However,

---

[155] See TransAlta Enterprises Corp., 75 FERC ¶ 61,268 at 61,875 (1996), and Energy Alliance Partnership, 73 FERC ¶ 61,019 at 61,030-31 (1995) (Energy Alliance).

[156] Canadian Niagara Power Company, 87 FERC ¶ 61,070 (1999).

[157] Fortis Ontario, Inc. and Fortis US Energy Corp., 115 FERC ¶ 61,110 (2006).

this general requirement does not apply to situations involving sales of power to or from a foreign utility outside of the Commission's jurisdiction.[158]

178. The Commission proposes to retain its current policy when reviewing a foreign seller's application for market-based rate authorization consistent with our overall approach discussed herein. The Commission seeks comments regarding whether this current policy is adequate to grant market-based rate authorization to such sellers.

3. Change in Status

179. In early 2005, the Commission clarified and standardized market-based rate sellers' reporting requirement 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,[159] 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. The rule provided that a change in status includes, but is not limited to: (i) ownership or control of generation or transmission facilities or inputs to electric power production other than fuel supplies, or (ii) affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation or transmission facilities or inputs to electric power production, or

---

[158] Energy Alliance, 73 FERC ¶ 61,019 at 61,031; TransAlta, 75 FERC ¶ 61,268 at 61,876.

[159] Order No. 652 at P 47.

affiliation with any entity that has a franchised service area.[160] A seller's experiencing one of these changes would trigger the notification requirement.[161]

180. The Commission has provided further guidance on change in status filings in several cases. In Calpine Energy Services, L.P.,[162] the Commission clarified that sellers making a change in status filing to report an energy management agreement are required to make an affirmative statement regarding whether the agreement transfers control of any assets and whether it results in any material effect on the conditions the Commission relied on when granting market-based rates. The Commission also clarified 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 Federal Power Act. To the extent the seller has made a section 203 filing that it submits is being made out of an abundance of caution and thus has voluntarily consented to the Commission's 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).[[163]]

---

[160] See 18 CFR 35.27(c) (2005).

[161] If a seller ceases to do business, or, in the event of its dissolution, such seller should file a notice of cancellation of its rate schedule.

[162] 113 FERC ¶ 61,158 at P 13 (2005).

[163] Id. at P 14 (footnotes omitted).

181. In addition, market-based rate sellers must report as a change in status each cumulative increase in generation of 100 MW or more that has occurred since the most recent notice of change in status filed by that seller (i.e., multiple increases in generation that individually do not exceed the 100 MW threshold must all be reported once the aggregate amount of such increases reaches 100 MW or more).[164] The Commission reserves the right to require additional information, including an updated market power analysis, if necessary to determine the effect of an entity's change in status on its market-based rate authority.[165]

182. In Order No. 652, the Commission identified a number of issues that could be pursued in the instant rulemaking proceeding. The Commission had proposed in that rulemaking proceeding to include fuel supplies as an input to electric power production the acquisition of which would be a reportable change in status. However, in the final rule, the Commission determined that this issue would be more appropriately raised in the instant rulemaking proceeding, and stated that the Commission would provide

[164] See Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 68. The reporting requirement is triggered only by net, rather than gross, increases in generation capacity of 100 MW or more. For example, capacity decreases associated with changes in generation capacity or expiration of capacity under long-term purchase contracts should be netted against generation capacity increases to determine whether the 100 MW materiality threshold has been reached. The Commission has adopted a netting approach in determining whether the materiality threshold has been reached, subject to the cumulative 100 MW threshold. See Order No. 652-A, 111 FERC ¶ 61,413 at P 24-25.

[165] Order No. 652 at P 95.

opportunity for interested persons to propose modifications to the existing approach in this proceeding.[166] Accordingly, the Commission solicits comments 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 proposes to align this reporting requirement to reflect the consideration of other barriers to entry as part of the vertical market power analysis, and commenters should refer to the discussion of other barriers to entry herein where the Commission proposes to clarify what constitutes an input to electric power production as part of the Commission's review of vertical market power.

183. In Order No. 652, the Commission clarified that the reporting of transmission outages per se as a change in status was not required. However, to the extent a transmission outage affects, on a long-term basis (e.g., an extended outage of a circuit or substation), whether the seller satisfies the Commission's concerns regarding horizontal or vertical market power (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 would be required. The Commission also stated that it would consider this matter further in the context of this rulemaking in the transmission market power part of the market power analysis.[167] We propose,

---

[166] Id. at P 58.

[167] Id. at P 75.

consistent with Order No. 652, not to require the reporting of transmission outages per se as a change in status. We seek comment on this proposal.

184. The Commission declined in Order No. 652 to narrow or delineate the definition of control. The Commission noted that, historically, if a seller has control over certain capacity such that it 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. Further, the capacity associated with contracts that confer operational control of a facility to an entity other than the owner must be assigned to the entity exercising control over that facility. 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.[168] As discussed above, the horizontal market power section herein seeks comment on a number of issues concerning control and commitment of generation.

185. In Order No. 652 we did not expand the triggering events for a change in status filing 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). In

---

[168] Id. at P 47.

Order No. 652, we concluded that the reporting obligation should extend only to changes in circumstances within the knowledge and control of the seller. However, in Order No. 652, we stated that interested persons could pursue in the instant rulemaking whether the Commission should expand the triggering events for a change in status filing. Accordingly, we invite comments generally on whether the Commission should expand the triggering events beyond 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 adopted in Order No. 652.

4. Third-Party Providers of Ancillary Services

186. 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) would also provide ancillary services.[169] The Commission also left open the door that ancillary services could be provided on other than a cost-of-service basis. In Order No. 888, 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.[170] In Ocean

---

[169] See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720-21.

[170] Id.; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,237-38.

Vista Power Generation, L.L.C. (Ocean Vista),[171] 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. The Commission also noted that it would entertain alternative explanations and approaches.

187. In Ocean Vista, the Commission also offered more detailed guidance for what a market power study for ancillary services markets should include: (1) defining a relevant product market for each ancillary service, which should include the applicant's product, together with other products that, from the buyer's perspective, are good substitutes; (2) identifying the relevant geographic market, which could include all potential suppliers of the product from whom the buyer could obtain the service, taking into account relevant factors which may include the other suppliers' locations, the physical capability of the delivery system and the cost of such delivery, and important technical characteristics of the suppliers' facilities; (3) establishing market shares for all suppliers of the ancillary services in the relevant geographic markets; and (4) examining other barriers to entry.

188. The guidance offered by the Commission in Order No. 888 and Ocean Vista was designed for two purposes: to ensure that sellers of ancillary services do not exercise

---

[171] 82 FERC ¶ 61,114 at 61,406-07.

market power and to further the goal of promoting competition in ancillary service markets.

189. However, in Avista Corporation,[172] the Commission stated that there remained two problems hindering the development of ancillary service markets. First, access to critical data may preclude many potential sellers of ancillary services from performing reliable market analyses. Second, without an alternative means of regulating ancillary service rates at an early stage in the development of competitive wholesale power markets, the Commission may not be able to encourage sufficient market entry of third-party providers of ancillary services.

190. Accordingly, the Commission adopted a policy wherein third-party ancillary service providers that cannot 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.

191. In this regard, the Commission stated that it will apply this policy only to applicants who are authorized to sell power and energy at market-based rates. In addition, the Commission stated that it will not apply this approach to sales of ancillary services by a third-party supplier in the following situations: (1) the approach will not apply to sales to a regional transmission organization (RTO) or an independent system

---

[172] 87 FERC ¶ 61,223, order on reh'g, 89 FERC ¶ 61,136 (1999) (Avista).

operator (ISO), i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties (the Commission stated that its experience to date indicates that the data problems associated with market analysis involving sales to an ISO, for example, should not be insurmountable and an appropriate showing of a lack of market power can be made);[173] (2) to address affiliate abuse concerns, the approach will not apply to sales to a traditional, franchised public utility affiliated with the third-party supplier, or to sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) the approach will not apply to sales to a public utility who is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers (the Commission indicated that it is open, however, to considering requests for market-based rates in such circumstances on a case-by-case basis).[174]

---

[173] With the formation of RTOs and ISOs, several RTO/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.

[174] Avista, 87 FERC at 61,883 n. 12.

192. The Commission based its policy as announced in Avista 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.[175] 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. The Commission stated that it believes that this protection, in conjunction with the Internet-based site requirement, will provide an appropriate and effective safeguard against potential anticompetitive behavior.

193. The information contained in the Internet-based site would include service availability, prices, and requests granted and denied. To further monitor development of market entry, the Commission required third-party suppliers to file with the Commission

[175] The Commission stated that it is cognizant of, but will address separately and at the appropriate time, situations in which it becomes apparent that, due to changes in ancillary services markets, competitive prices would be higher than the transmission provider's cost-based rate, were it not for the transmission provider's obligation to meet all demand for ancillary services at such a rate.

one year after their Internet-based site is operational (and at least every three years thereafter[176]) a report detailing their activities in the ancillary services market.

194. In particular, the Commission stated that:

> [i]f the applicant cannot perform a study showing that it lacks market power in the provision of ancillary services, it may receive flexible rates provided it safeguards against potential anticompetitive behavior by establishing an Internet-based site for providing information regarding, and conducting, ancillary services transactions. The site would include postings of offers of services available and their offering prices and would provide customers with the ability to request services and make bids for these services. The site would also contain information about accepted and denied requests and the reasons for denial. The site should conform to the applicable OASIS Standards and Communications Protocols (Version 1.3).[[177]]

195. We propose to retain our current approach in this regard. We seek comment on whether we should modify or revise our current approach and, if so, how. Also, we seek comment on whether our current conditions such as the requirement to establish an Internet-based site continue to be necessary.

---

[176] The Commission reserves the right to require that such a report be filed at any time.

[177] Avista, 87 FERC at 61,884. We note that section 37.6(d)(5) of the Commission's regulations states: "Any entity offering an ancillary service shall have the right to post the offering of that service on the OATT if the service is one required to be offered by the Transmission Provider under the pro-forma tariff prescribed by part 35 of this chapter. Any entity may also post any other interconnected operations service voluntarily offered by the Transmission Provider. Postings by customers and third parties must be on the same page, and in the same format, as posting of the Transmission Provider."

H. Proposed Revisions To Regulations

1. Section 35.27 [Currently] Power Sales at Market-Based Rates

196. Subsections (a) and (b) of this section were added by Order No. 888 in order to implement the post-1996 exemption for new generation and to clarify the authority of state commissions respectively. Order No. 652 later added subsection (c) to implement the change in status reporting requirement.

197. This NOPR proposes to eliminate the post-1996 exemption, and thus the proposed regulatory text deletes subsection (a). Subsection (c) is proposed to move to subpart H section 35.43, and thus the proposed text deletes section 35.27(c). This leaves only current subsection (b) in 35.27. The proposed regulatory text does not revise the language in any way and merely renumbers current subsection (b) to reflect the absence of the other subsections.

198. With the changes proposed herein, the current section heading, "Power Sales at Market-Based Rates," will no longer be pertinent. The Commission proposes to amend the heading to "Authority of State Commissions" to reflect the content of the remaining provision.

2. Section 35.36 Generally

199. This section is proposed to define certain terms specific to Subpart H and to

explain the applicability of Subpart H.[178] Some of these terms were put in place recently when the Commission codified certain market behavior rules in Order No. 674.[179] Subsection (a)(1) explains that "seller" refers to a public utility with authority to, or seeking authority to, engage in sales for resale of electric energy, capacity or ancillary services at market-based rates to make clear that Subpart H deals exclusively with market-based rate power and ancillary services sales. The proposed regulations define Category 1 sellers and Category 2 sellers to assist in understanding the parameters of the updated market power analysis requirement. Subsection (a)(4) defines inputs to electric power production in order to simplify section 35.37(e) regarding other barriers to entry. Subsection (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 territory that have captive customers. Last, subsection (a)(6) provides a definition for non-regulated affiliated entities, which appears in several places in the proposed regulations.

200. Subsection (b) is intended to leave room for certain provisions that do not apply to a particular seller should the Commission make a finding, for instance, that a franchised public utility has no captive customers and hence section 35.39(b) is not applicable.

---

[178] We note that we also proposed to change the title of Subpart H from 'Wholesale Sales of Electricity at Market-Based Rates' to 'Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates'.

[179] Conditions for Public Utility Market-Based Rate Authorization Holders, Order No. 764, FERC Stats. & Regs. ¶ 31,208, 114 FERC ¶ 61,163 (2006).

201. We solicit comments on whether further or different language than that proposed here should be incorporated in our regulations.

3. <u>Section 35.37 Market Power Analysis Required</u>

202. 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 without providing too much detail. The Commission is cognizant that the finer points of the market power analysis change over time as individual orders consider new facts and as precedent shifts to follow the evolution of the power industry; the proposed regulations should not be so detailed as to require revision from time to time to follow these changes.

203. We solicit comments on the scope of the language that should be incorporated in the regulations.

4. <u>Section 35.38 Mitigation</u>

204. The NOPR raises questions concerning the current approach and seeks comments regarding any changes the Commission should adopt. In addition, we propose to characterize the informal term "up to" cost-based rates as "priced at no higher than a cost-based ceiling reflecting the cost of the units expected to provide service." We seek comments on whether further or different language than that proposed here should be incorporated in our regulations.

5. <u>Section 35.39 Affiliate Provisions</u>

205. This section governs affiliate transactions and affiliate relationships and establishes affiliate conditions that a seller must satisfy as a condition of its market-based rate authority. Subsection (a) includes a provision expressly prohibiting sales between a franchised public utility and any of its non-regulated power sales affiliates without first receiving authorization of the transaction under section 205 of the FPA. This subsection 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. We seek comments on the proposal to include this provision in the Commission's regulations.

206. Subsections (b)-(e) contain the market-based rate code of conduct provisions governing the relationship between a franchised public utility and its non-regulated power sales and power brokering affiliates. The provisions of this subsection apply to all franchised public utilities with captive customers. This subsection includes provisions governing the separation of employees, the sharing of market information, sales of non-power goods or services, and power brokering. It proposes that, for purposes of applying the provisions of this section, 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 public utility) are considered to be part of the franchised public utility, and entities acting on behalf of and for the benefit of a non-regulated affiliate of a franchised public utility (such as affiliated power marketers and power producers and

entities managing the generation assets of the affiliated power marketers and producers) are considered to be part of the non-regulated affiliates. This section is an integral part of the Commission's conditions regarding affiliate abuse where captive customers are concerned. We seek comments on the proposal to include the affiliate provisions in the regulations**.**

6. Section 35.40 Ancillary Services

207. This provision restricts sales of ancillary services to those specific geographic markets for which the Commission has authorized market-based rate sales of such. In addition, this section lays out the limitations on third-party ancillary services sales provided in Avista Corporation.[180]

7. Section 35.41 Market Behavior Rules

208. Recently, the Commission rescinded two of its market behavior rules and codified the remainder in section 35.37 of new Subpart H. Also, in a Final Rule issued concurrently with this NOPR the Commission is revising the record retention period from three years to five years. In this NOPR, we propose to move these market behavior rules, unchanged, from section 35.37 to section 35.41.

---

[180] Avista Corporation, 87 FERC ¶ 61,223, order on reh'g, 89 FERC ¶ 61,136 (1999).

8. Section 35.42 Market-Based Rate Tariff

209. This proposed provision imposes the requirement that each seller (or its corporate parent) have on file with the Commission the market-based rate tariff that is appended hereto at Appendix A.

9. Section 35.43 Change in Status Reporting Requirement

210. This section incorporates the provision currently found at subsection 35.27(c), which was codified by Order No. 652. No modifications to the existing language are proposed. We seek comment on whether any changes are warranted.

IV. Information Collection Statement

211. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[181] 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 proposes 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.

[181] 5 CFR § 1320.11 (2005).

212. The Commission has previously required utilities seeking market-based rate authority to file a market power analysis with the Commission; the Commission now proposes to codify that requirement in the Commission's regulations. This proposal reflects the Commission's existing practice and will not impose any additional burden, with the following exception.

213. Section 35.27(a) of the Commission's regulations 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 control area is post-July 9, 1996 generation, such applicant is not required to submit a generation market power analysis. In this NOPR, the Commission proposes to eliminate the express exemption provided in section 35.27(a). This proposal 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 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. Because the Commission allows an applicant to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, any burden of document preparation occasioned by the proposed elimination of section 35.27(a) should be minimal. Moreover, any burden of document preparation caused by

the proposed elimination of section 35.27(a) should apply for the most part only with regard to generation market power analyses required to support an initial application for market-based rate authority.

214. The second filing requirement proposed in this NOPR is that all market-based rate sellers file one market-based rate tariff per corporate family. The MBR tariff proposed by the Commission is appended to this NOPR. The proposed tariff, coupled with the proposed regulations, will simplify the content of MBR tariffs filed with the Commission and decrease the burden of document preparation by providing a clearly defined statement of the information sought by the Commission. Utilities will only be required to fill in the company-specific information, which lessens the burden of drafting documentation. A tariff of general applicability will also give the Commission consistency on review and clarity regarding the connections between parent and affiliate utilities in its analysis. Although the requirement to file the specified MBR tariff may cause a minimal burden of document preparation and organization for existing market-based rate sellers, long-term benefits will be realized for utilities as well as the Commission.

215. To retain market-based rate authority, the Commission currently requires that sellers file a triennial review. In this NOPR, the Commission proposes to codify the requirement that certain sellers with market-based rate authority file a triennial review with the Commission to retain that authority. However, the Commission proposes that certain smaller utilities, Category 1 sellers, be relieved of their existing duty to file the

triennial review. Thus, larger sellers will not face a greater burden to provide the Commission with the information required for a triennial review, and the burden of supplying the updated analysis may be eliminated for certain smaller entities seeking to retain market-based rate authority.

216. 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 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, triennial reviews, and reporting requirements for changes in status for public utilities with market-based rate authority.

217. 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.[182] Comments are solicited 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.

[182] 44 U.S.C. § 3507(d) (2000).

Burden Estimate: The Public Reporting and records retention burden for all four proposed reporting requirements and the records retention requirement is as follows.[183]

Title: Electric Rate Schedule Filings (FERC-516).

Action: Revised Collection.

OMB Control No: 1902-0096

Data Collection	No. of Respondents	No. of Responses	Hours Per Response	Total Annual Hours
Initial Market Power Analysis	120	120	130	15,600
Market-Based Rate Tariff	650[184]	217	6	3,900
Triennial Review Category 1[185]	0	0	0	0
Triennial Review	600	200[187]	250	50,000

[183] These burden estimates apply only to this NOPR and do not reflect upon all of FERC-516.

[184] The number of respondents for market-based rate tariffs is expected to be 650. The figure 217 represents 650 respondents, per year, over the course of 3 years. Also, the 650 figure takes into account that parent companies will file for their affiliates.

[185] 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 or control transmission facilities, and must present no other vertical market power issues. The zero in this section represents that Category 1 Sellers are not responsible for filing triennial updates.

Category 2[186]

Totals

Total Annual hours for Collection: (Reporting + record retention, (if appropriate)=

hours.

Information Collection Costs: The total annual cost for Initial Market Power Analysis is estimated to be $2,340,000. Total annual cost for market-based rate tariffs is projected to be $195,300. Total annual cost for Triennial Reviews 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.

---

[186] Category 2 Sellers are any sellers not in Category 1.

[187] 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.

MBR Tariff: A MBR tariff for each corporate family with all current sellers to be filed with the Commission after the final rule is effective. In the future, a MBR tariff will be filed occasionally by each utility newly seeking market-based rate authority.

Triennial Review: Updated market power analysis filed every three years for Category 2 sellers seeking to retain market-based rate authority.[188]

Necessity of the Information

Market Power Analyses: Consistent with current practices, the market power analysis aids the Commission in determining whether an entity seeking market-based rate authority lacks market power and permits a determination that sales by that entity will be just and reasonable.

MBR Tariff: A market-based rate tariff filed for each corporate family, with all affiliates with market-based rate authority separately identified in the tariff, would improve the efficiency of the Commission in its analysis and determination of market-based rate authority. The MBR Tariff would allow the Commission to have a clear definition of the relationships between parent and affiliate utilities in assessing market-based rate authority and/or the investigation thereof. This will allow for better transparency with regard to what sellers each corporate family has, and a more customer friendly tariff. A tariff of

[188] Certain smaller entities (Category 1 sellers) are proposed to be exempted from this requirement.

general applicability will also reduce document preparation time overall and provide utilities with the clearly defined expectations of the Commission.

Triennial Review: The triennial review allows 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 proposed by this NOPR 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.[189]

Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502-8415, fax: (202) 273-0873, e-mail: michael.miller@ferc.gov. Comments on the requirements of the proposed rule may also be sent to the Office of Information and Regulatory

[189] *See* 44 U.S.C. § 3506(c) (2004).

Affairs, Office of Management and Budget, Washington, D.C. 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

V. **Environmental Analysis**

218. 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.[190] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.[191] The actions proposed here fall within the categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, or do not substantially change the effect of legislation or regulations being amended.[192] In addition, the proposed rule is categorically excluded as an electric rate filing submitted by a public utility under sections 205 and 206 of the FPA.[193] As explained above, this proposed rule addressing the issue of electric rate filings submitted by public utilities for market-based rate authority is clarifying in nature. Accordingly, no environmental assessment is necessary and none has been prepared in this NOPR.

---

[190] Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 30,783 (1987).

[191] 18 CFR § 380.4 (2005).

[192] See 18 CFR § 380.4(a)(2)(ii).

[193] See 18 CFR § 380.4(a)(15).

VI. Regulatory Flexibility Act Analysis

219. The Regulatory Flexibility Act of 1980 (RFA)[194] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities.[195] The proposed rule will be applicable to all public utilities seeking and currently possessing market-based rate authority. The Commission finds that the regulations proposed here should not have a significant impact on small businesses.

220. The submission of a market power analysis is currently required of all entities seeking authority to sell at market-based rates, and the proposed rule does not alter which entities will be required to file these analyses. The proposed rule does not create a new reporting requirement. It does, however, propose to 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 section 35.27(a) exemption, in time, would encompass all market participants as all pre-July 9, 1996 generation is retired.

---

[194] 5 U.S.C. §§ 601-12 (2000).

[195] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, 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 (2000). 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 (2004) (section 22, Utilities, North American Industry Classification System, NAICS).

Nevertheless, because the Commission allows an applicant to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any additional burden imposed by the proposed elimination of the section 35.27(a) exemption will be minimal. Thus, public utilities are currently prepared to submit market power analyses and this requirement does not pose a greater burden.

221. The proposed rule requires that each corporate family have on file one MBR tariff of general applicability, with all affiliates with market-based rate authority separately identified in the tariff. Although this may initially increase the burden of document preparation and organization for parent utilities, long-term benefits will be realized that reduce burdens on utilities and the Commission. A tariff of general applicability will decrease document preparation by providing a clearly defined statement of the information sought by the Commission. Moreover, a single tariff for each corporate family will reduce the filing burden on utilities. Small entities affiliated with a parent utility need not prepare a separate tariff; rather, they will merely add their company name to their parent utility's tariff. Thus, the burden is decreased.

222. 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 proposed regulations would result in fewer filings with the Commission than currently required for qualified smaller utilities' (Category 1) retention of market-

based rate authority. Those who do have to file are able to use short cuts described above (i.e., simplifying assumptions). Thus, the proposed rule would be less burdensome economically and reduce the frequency of document preparation for market-based rate authority retention for qualified smaller utilities.

VII. Comment Procedures

223. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[insert date _60__ days from publication in the FEDERAL REGISTER]**. Reply comments are due **[insert date 30 days after comment date]**. Comments and reply comments must refer to Docket No. RM04-7-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. Comments and reply comments may be filed either in electronic or paper format.

224. Comments and reply comments may be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Documents created electronically using word processing software should be filed in the native application or print-to-PDF format and not in a scanned format. This will enhance document retrieval for both the Commission and the public. Attachments that exist only in paper form may be scanned. Commenters filing electronically should not make a paper filing. Service of rulemaking

comments is not required. Commenters that are not able to file comments and reply comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, N.E., Washington, D.C., 20426.

225. All comments and reply comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments and reply comments on other commenters.

VIII. Document Availability

226. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

227. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

228. User assistance is available for eLibrary and the Commission's website during

normal business hours. For assistance, please contact FERC Online Support at 1-866-208-3676 (toll free) or (202)502-8222 (e-mail at FERCOnlineSupport@FERC.gov), or the Public Reference Room at (202) 502-8371, TTY (202)502-8659 (e-mail at public.referenceroom@ferc.gov).

List of subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

Magalie R. Salas,
Secretary.

In consideration of the foregoing, the Commission proposes to amend 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. Section 35.27 is revised 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.

(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 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; that do not own or control transmission facilities (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 or controls transmission facilities; that are not affiliated with a public utility with a franchised service territory; 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 sites for development of generation, fuel inputs such as coal facilities, and the transportation or distribution of inputs to electric power production such as gas storage, intrastate gas transportation and distribution systems, and rail cars/barges for the transportation of coal.

(5) Franchised public utility means a public utility with a franchised service obligation under state law and that has captive customers.

(6) Non-regulated power sales affiliate means 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.

(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) 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. ___, FERC Stats. & Regs. ¶ 31,___; 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.

(b) A market power analysis must address whether a Seller has horizontal and vertical market power.

(c) There will be a rebuttable presumption that a Seller lacks horizontal market power if it passes two indicative market power screens: first, a pivotal supplier analysis based on the annual peak demand of the relevant market and; second, 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. A Seller that has horizontal market power, or that has not rebutted a presumption of horizontal market power, is subject to mitigation, as described in § 35.38.

(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.

(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: a description of its affiliation, ownership or control of inputs to electric power production; a description of its ownership or control of intra-state transportation or distribution of inputs to electric power production; a description of its ownership or control of any sites for new generation capacity development; and a statement that it cannot erect barriers to entry in the relevant markets.

§ 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.

(b) Default mitigation consists of three distinct products: (i) sales of power of one week or less priced at the Seller's incremental cost plus a 10 percent adder; (ii) 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 (iii) 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) 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 public utility Seller with a franchised service territory and a non-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act. Failure to satisfy this condition will constitute a violation of the Seller's market-based rate tariff. All authorizations to engage in affiliate wholesale sales of electricity must be listed in a Seller's market-based rate tariff.

(b) Separation of functions.

(1) For the purpose of this subsection, entities acting on behalf of and for the benefit of a franchised public utility (such as entities managing 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 a franchised public utility's non-regulated power sales affiliates are considered part of the non-regulated affiliated entities.

(2) 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.

(c) Information sharing.

All market information shared 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. Shared employees in a support role are not bound by this provision, but they may not serve as a conduit of information to non-support personnel.

(d) Non-power goods or services.

(1) Sales of any non-power goods or services by a franchised public utility, including sales made to or through its affiliated exempt wholesale generators or qualifying facilities, to a non-regulated power sales affiliate will be at the higher of cost or market price.

(2) Sales of any non-power goods or services by a non-regulated power sales affiliate to an affiliated franchised public utility will not be at a price above market.

(e) Other.

(1) To the extent a non-regulated power sales affiliate seeks to broker power for an affiliated franchised public utility:

(a) the non-regulated power sales affiliate must offer the franchised public utility's power first;

(b) the arrangement between the non-regulated power sales affiliate and the franchised public utility must be non-exclusive; and

(c) the non-regulated power sales affiliate may not accept any fees in conjunction with any brokering services it performs for an affiliated franchised public utility.

(2) To the extent a franchised public utility seeks to broker power for a non-regulated power sales affiliate:

(a) the franchised public utility will be required to charge the higher of its costs for the service or the market rate for such services;

(b) the franchised public utility will be required to market its own power first, and simultaneously make public (on an electronic bulletin board and/or the Internet) any market information shared with its affiliate during the brokering; and

(c) the franchised public utility will post on an electronic bulletin board and/or the Internet the actual brokering charges imposed.

§ 35.40 Ancillary services.

(a) If a Seller seeks authority to make sales of ancillary services at market-based rates, it may offer such services provided the service has been authorized by the Commission and only in specific geographic markets as the Commission has authorized.

(b) If a Seller is authorized by the Commission to make sales of ancillary services at market-based rates as a third-party ancillary services provider:

(1) Seller shall establish an Internet-based site for providing information regarding ancillary services transactions including, prior to making transactions, postings of offers of services available and offering prices; procedures under which all customers would request service and make bids; postings of the actual transaction prices after the transactions are consummated; and accepted and denied requests and the reasons for denial. The site should conform to the applicable OASIS Standards and Communications Protocols.

(c) Seller is not authorized to make sales of ancillary services at market-based rates as a third-party ancillary services provider:

(1) To a regional transmission organization or an independent system operator (other than those ancillary services that are subject to § 35.40(a)) that has no ability to self-supply ancillary services but instead depends on third parties;

(2) When the underlying transmission service is on the transmission system of a transmission provider with whom the Seller is affiliated; or

(3) To a public utility who is purchasing ancillary services to satisfy its own Open Access Transmission Tariff requirements to offer ancillary services to its own transmission customers, unless Seller(s) receives separate authorization by the Commission.

§ 35.41 Market Behavior Rules.

(a) Unit operation**.** Where a Seller participates in a Commission-approved organized market, Seller will 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 power market. 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. Seller will 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 Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller shall 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 shall 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 shall adhere to such other standards and requirements for price reporting as the Commission may order.

(d) Records retention. Seller shall 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 Market-based rate tariff.

(a) In addition to other requirements in subpart A, every public utility that is authorized to sell electric energy at market-based rates pursuant to section 205 of the Federal Power Act must have on file with the Commission a tariff of general applicability. Such tariff must be the market-based rate tariff contained in Order No. ___, FERC Stats. & Regs. ¶ 31,___ (Final Rule on Market-Based Rates for Wholesale Sales of Electricity by Public Utilities).

(b) The market-based rate tariff contained in Order No. ___, FERC Stats. & Regs. ¶ 31,___, must be filed by Sellers who have been granted market-based rate authority prior to the issuance of Order No. ______, in accordance with Order No. _____, FERC Stats. & Regs. ¶ 31, ___ (Final Rule on Electronic Tariff Filing). A market-based rate tariff must be filed by a Seller who is initially seeking market-based rates at the time it applies for market-based rate authorization.

(c) Each corporate family will file a single market-based rate tariff, with all affiliates with market-based rate authority separately identified in the tariff.

§ 35.43 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 transmission facilities or inputs to electric power production other than fuel supplies, or

(2) Affiliation with any entity not disclosed in the 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.

(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. Failure to timely file a change in status report constitutes a tariff violation.

Appendix A

Proposed Market-Based Rate Tariff

Market-Based Rate Tariff

Seller(s) Under This Tariff:	Docket No. Authorizing Market-Based Rates:
ABC, Inc.	Docket No. ERXX-XXX-XXX
XYZ, LLC	Docket No. ERXX-XXX-XXX
Etc.	etc.

1. Availability: Electric energy, capacity and ancillary services are available under this tariff for wholesale sales to purchasers with whom seller has contracted. Not all services may be available from all sellers listed. 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.

2. Applicability: This tariff is applicable to all wholesale sales of electric energy, capacity and ancillary services by seller.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and seller.

4. Other Terms and Conditions: All other terms and conditions not listed herein shall be established by agreement between the purchaser and seller.

5. Effective Date: This Rate Schedule is effective on the date of compliance with the final rule on Electronic Tariff Filings, Order No. ___, FERC Stats. & Regs. ¶ 31,___.

Market-Based Rate
Tariff
Appendix A

<u>Docket No. Approving Affiliate Sales</u>

Docket No. ERXX-XXX-XXX

Docket No. ERXX-XXX-XXX

Etc.

☐ Check if Not Applicable

<u>Docket No. Imposing Restrictions on Market-Based Rate Authority</u>

Docket No. ERXX-XXX-XXX

Docket No. ERXX-XXX-XXX

Etc.

☐ Check if Not Applicable

Appendix B

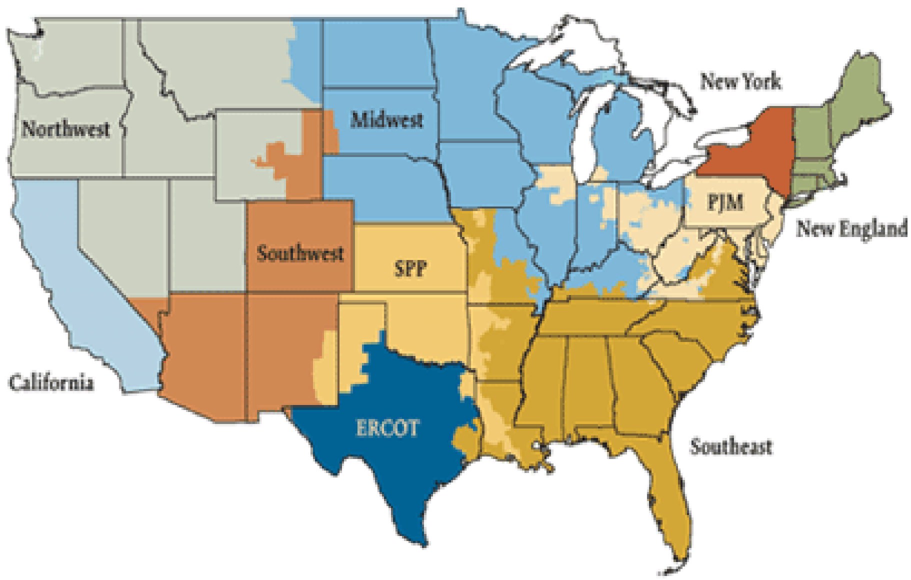
Schedule for Regional Triennial Review Process

All Category 2 sellers that own or control generation in the California, Northwest, Southwest, Midwest, SPP, Southeast, PJM, New York, and New England regions during the period specified below (Qualification Period) will file updated market power analyses within the filing period specified in the following schedule. Triennial Reviews should reflect the most recently available historical data from the calendar year prior to the year of filing. The regions are depicted in the map that follows. (Source: Federal Energy Regulatory Commission, 2004 State of the Markets Report, staff report prepared by the Office of Market Oversight & Investigations, June 2005.)

Region	Qualification Period	Filing Period
PJM	2006	April 1-30, 2007
New York	2006	July 1-30, 2007
New England	2006	October 1-30, 2007
Midwest	2007	April 1-30, 2008
SPP	2007	July 1-30, 2008
Southeast	2007	October 1-30, 2008
California	2008	April 1-30, 2009
Northwest	2008	July 1-30, 2009
Southwest	2008	October 1-30, 2009
PJM	2009	April 1-30, 2010
New York	2009	July 1-30, 2010
New England	2009	October 1-30, 2010
Midwest	2010	April 1-30, 2011
SPP	2010	July 1-30, 2011
Southeast	2010	October 1-30, 2011
California	2011	April 1-30, 2012

Northwest	2011	July 1-30, 2012
Southwest	2011	October 1-30, 2012

This review cycle will be repeated in subsequent years.



Appendix C

Standard Screens Format

AMOUNTS LISTED ARE FOR ILLUSTRATIVE PURPOSES ONLY

Pivotal Supplier Analysis

Supply:	Row	(MW)	Reference
Applicant's Installed Capacity	A	19,500	Workpaper 1
Applicant's Long-Term Firm Purchases	B	500	Workpaper 6
Applicant's Long-Term Firm Sales	C	(1,000)	Workpaper 2
Applicant's Imports (Limited by Simultaneous Import Capability)	D	0	Workpaper 5
Non-Affiliate Local Installed Capacity	E	8,000	Workpaper 1
Non-Affiliate Long-Term Firm Purchases	F	500	Workpaper 6
Non-Affiliate Long-Term Firm Sales	G	(2,500)	Workpaper 2
Non-Affiliate Uncommitted Capacity Imports	H		
(Limited by Simultaneous Import Capability)	I	3,500	Workpaper 5
Control Area Reserve Requirement	J	(2,160)	Workpaper 3
Amount of Line J Attributable to Applicant, if any	K	(2,160)	Workpaper 3
	L		
Total Uncommitted Supply (SUM A,B,C,D,E,F,G,I,J,Q)	M	9,840	
	N		
Load:	O		
Control Area Annual Peak Load	P	18,000	Workpaper 4
Average Daily Peak Native Load in Peak Month	Q	(16,500)	Workpaper 4
Amount of Line Q Attributable to Applicant, if any	R	(16,500)	Workpaper 4
	S		
Wholesale Load (-SUM P,Q)	T	(1,500)	
	U		
Net Uncommitted Supply (SUM M,T)	V	8,340	
	W		
Applicant's Uncommitted Capacity (SUM A,B,C,K,R)	X	340	

PASS

AMOUNTS FOR ILLUSTRATIVE PURPOSES ONLY

Wholesale Market Share Analysis:

	Row	Q1	Q2	Q3	Q4	Reference
		(MW)	(MW)	(MW)	(MW)	
Applicant's Installed Capacity	A	19,500	19,500	19,500	19,500	Workpaper 1
Applicant’s Long-Term Firm Purchases	B	500	500	500	500	Workpaper 6
Applicant's Long-Term Firm Sales	C	(1,000)	(1,000)	(1,000)	(1,000)	Workpaper 2
Applicant’s Seasonal Average Planned Outages	D	(4,000)	(3,000)	(800)	(3,500)	Workpaper 7
Applicant’s Imports (Limited by Simultaneous Import Capability)	E	0	0	0	0	Workpaper 5
Average Peak Native Load in the Season	F	(11,500)	(10,000)	(12,500)	(11,500)	Workpaper 8
Amount of Line F Attributable to Applicant, if any	G	(11,500)	(10,000)	(12,500)	(11,500)	Workpaper 8
Amount of Line F Attributable to Others, if any	H	(0)	(0)	(0)	(0)	Workpaper 8
Control Area Reserve Requirement	I	(1,500)	(1,320)	(1,560)	(1,500)	Workpaper 3
Amount of Line I Attributable to Applicant, if any	J	(1,500)	(1,320)	(1,560)	(1,500)	Workpaper 3
Amount of Line I Attributable to Others, if any	K	(0)	(0)	(0)	(0)	Workpaper 8
Non-Affiliate Local Installed Capacity	L	8,000	8,000	8,000	8,000	Workpaper 1
Non-Affiliate Long-Term Firm Purchases	M	500	500	500	500	Workpaper 6
Non-Affiliate Long-Term Firm Sales	N	(2,500)	(2,500)	(2,500)	(2,500)	Workpaper 2
Non-Affiliate Local Seasonal Average Planned Outages	O	(800)	(200)	(300)	(400)	Workpaper 7
Non-Affiliate Uncommitted Capacity Imports	P					
(Limited by Simultaneous Import Capability)	Q	5,000	4,500	3,500	4,000	Workpaper 5
	R					
Total Competing Supply (SUM L,M,N,O,Q,H,K)	S	10,200	10,300	9,200	9,600	
Applicant's Uncommitted Capacity (SUM A,B,C,D,E,G,J)	T	2,000	4,680	4,140	2,500	
Total Seasonal Uncommitted Capacity (SUM S,T)	U	12,200	14,980	13,340	12,100	
	V					
Applicant's Market Share (T/U)	W	16.39%	31.24%	31.03%	20.66%	
		PASS	FAIL	FAIL	FAIL	

Appendix D
Commenters

Allen Freifeld (Mr. Freifeld)

Ameren Corporation (Ameren)

American Electric Power (AEP)

Alliance Energy Corporate Services, Inc. (Alliance)

Allegheny Energy, Inc. (Allegheny)

American Antitrust Institute (American Antitrust)

American Forest & Paper Association (Forest & Paper)

American Public Power Association (APPA)

Analysis Group Inc. (Analysis Group)

Andrew N. Kleit (Kleit)

Arizona Public Service Company (APS)

Bates White, LLC (Bates White)

Benjamin Hobbs (Dr. Hobbs)

Bonneville Power Administration (BPA)

Boston Pacific Company (Boston Pacific)

California Electricity Oversight Board (California Board)

California Public Utilities Commission (California Commission)

Calpine Corporation (Calpine)

Cinergy Services, Inc. (Cinergy)

Cogeneration Association of California, Energy Producers and Users Coalition, Nevada Independent Energy Coalition, March Point Cogeneration and Sumas Energy (CoGen)

Consolidated Edison Company of New York, Inc. (ConEd)

Constellation Energy Group Inc. (Constellation)

Consumers Energy Company (Consumers)

David DeRamus (Dr. DeRamus)

David S. Portnoy (Mr. Portnoy)

Duke Energy Corporation (Duke)

East Texas Cooperatives (East Texas Coop)

EEI and Alliance of Energy Suppliers (EEI)

ELCON

Electric Power Supply Association (EPSA)

Entergy Services, Inc. (Entergy)

Federal Trade Commission (FTC)

FirstEnergy Service Company (FirstEnergy)

Harquahala Generating Company, LLCC (Harquahala)

Harvey Reiter (Reiter)

Independent Energy Producers

Industrial Consumers (ELCON, AISI, ACC and AF&PA) (Industrial Consumers)

Industrial Energy Users – Ohio (IEU- Ohio)

Intergen Service, Inc. (Intergen)

James B. Bushnell (Dr. Bushnell)

Joint Consumer Advocates (Advocates)

John Hilke (Dr. Hilke)

Julia Frayer (Dr. Frayer)

Kansas City Power & Light Company (Kansas City Power)

Keyspan-Ravenswood LLC (Keyspan-Ravenswood)

Lafayette Utilities Systems (Lafayette)

Louisiana Public Service Commission (Louisiana Commission)

Maryland Public Service Commission (Maryland Commission)

Mayflower LP (Mayflower)

MidAmerican Energy Company (MidAmerican)

Midwest Municipal Transmission Group (Midwest Municipal Transmission)

Midwest Stand-Alone Transmission Companies (Midwest Stand-Alone Transmission)

Montana Consumer Counsel (Montana Counsel)

Montana Public Service Commission (Montana Commission)

Morgan Stanley Capital Group, Inc. (Morgan Stanley)

National Association of Regulatory Utility Commissioners (NARUC)

National Grid USA (National Grid)

NRECA

NRG Energy, Inc. (NRG)

Pace Global Energy Services, LLC (Pace Global)

PacifiCorp (PacifiCorp)

PJM Industrial Customer Coalition (PJM Industrial Consumers)

Power Systems Engineering, Inc. (Power Systems)

Powerex Corp. (Powerex)

Progress Energy, Inc. (Progress Energy)

Public Utilities Commission of Ohio (Ohio Commission)

Puget Sound Energy (Puget)

Robert Garvin (Mr. Garvin)

Schwab Capital Markets, L.P. (Schwab)

Southern Company Services, Inc. (Southern)

Susan F. Tierney and Paul J. Hibbard (Tierney & Hibbard)

The PSEG Companies (PSEG)

Tractebel Energy Marketing, Inc. (Tractebel)

Transmission Access Policy Study Group (TAPS)

Transmission Dependent Utility Systems (TDU Systems)

Utility Economic Engineers (Economic Engineers)

Virginia State Corporation Commission (Virginia Commission)

Wisconsin Electric Power Company (Wisconsin Electric)

Wisconsin Public Service Commission (Wisconsin Commission)

Xcel Energy Services Inc. (Xcel)

Appendix E

Summary of Comments

1. **Horizontal Market Power**

The Commission convened two technical conferences on June 9, 2004 and January 27, 2005, to consider whether, and to what extent, the Commission should modify the interim generation market power screens and the appropriate mitigation for those sellers found to have generation market power. Among the specific issues that the Commission considered was the application of the generation market power screens, including the 20 percent threshold, the application of the DPT or other alternatives for measuring generation market power, extending the market power screens to cover capacity and generation based ancillary services and retention of the section 35.27 (a) exemption of generation units built after July 9, 1996 from the requirement to demonstrate a lack of generation market power. The technical conference also considered issues regarding regional geographic markets and other mitigation the Commission should consider.

1. After the technical conferences, the Commission invited all interested parties to submit comments. Many parties submitted comments.

a. **Indicative Screens**

(i) **Relevant Market**

2. Many investor-owned utilities (IOUs) oppose the Commission's use of control areas as the default geographic market outside of RTO/ISOs.[196] IOUs state that the Commission should detail the technical criteria and data needed that will be used to judge whether the screens can be based on a regional market.[197] Virginia Commission states that the Commission should analyze the actual physical characteristics of a transmission system, including any transmission constraints, when determining the relevant geographic market, and that sellers should not be able to use the RTO/ISO footprint as the default relevant geographic market.[198] BPA suggests that sellers should be permitted to include specific references and quantitative estimates of any capacity limitations that result from operational constraints which would further limit marketing discretion and the seller's potential to exercise market power.[199]

(ii) Native Load

3. Ohio Commission states that the screens should take into account the level of market concentration and the other obligations that the seller must meet, such as the

---

[196] Cinergy Comments (March 14, 2005) at 9-10; PacifiCorp Comments (March 14, 2005) at 2; and Puget Comments (March 14, 2005) at 1-5.

[197] Puget Comments (March 14, 2005) at 2, 3, 8.

[198] Virginia Commission Comments (June 30, 2004) at 3; see also APPA Comments (June 30, 2004) at 23 and Forest & Paper Comments (June 30, 2004) at 9.

[199] BPA Comments (June 30, 2004) at 4.

native load obligations and any provider of last resort obligations.[200] Louisiana Commission states that generation that primarily serves retail load should be excluded from the analysis, and AEP states that the screens are flawed because they do not consider the seller's own load and many firm transmission service reservations as well as the amount of non-seller load required to serve the market.[201]

4. APPA and others present an opposing view. APPA states that the screens should not use uncommitted capacity, and that alternatively the Commission should narrow deductions of capacity and load that are in the wholesale market and require the submission of contracts to support the legitimacy of such deductions.[202] Bates White agrees that native load should not be excluded and that to do so is inconsistent with the analysis in section 203 proceedings.[203] Montana Counsel states that generation suppliers should not be able to deduct capacity reserved for other utilities' native load.[204] Some commenters note that there is no way to perfectly account for native load, so only supply that has not been excluded from the analysis as native load should be allowed to be sold

---

[200] Ohio Commission Comments (June 30, 2004) at 3-4; see also Cinergy Comments (March 14, 2005) at 17.

[201] Louisiana Commission Comments (June 30, 2004) at 2; AEP Comments (June 30, 2004) at 15.

[202] APPA Comments (June 30, 2004) at 22; see also Intergen Comments (July 1, 2004) at 4.

[203] Bates White Comments (June 30, 2004) at 3-4.

[204] Montana Counsel Comments at 4.

at market-based rates.[205] Other ideas included allowing sellers to deduct the minimum load overall, not just the minimum peak day load.[206]

(iii) Screen Modifications

5. Independent power producers and transmission dependent utilities (IPPs/TDUs) and Industrial Consumers expressed general support for the current screens. NRECA argues that the pivotal supplier screen is ineffective and should be revised particularly with regard to the native load and operating reserve deductions.[207] NRECA states that the market share screen does a better job of identifying potential market power than the pivotal supplier, but that the 20 percent threshold is too high.[208] AEP argues that unreasonably high levels of supply are necessary for vertically-integrated utilities to have less than 20 percent market share, and Southern states that the threshold is very low.[209]

6. TAPS and American Antitrust argue that the screens should consider prices, not just supply and demand.[210] Dr. Julia Frayer argues that the Commission should add

---

[205] APPA Comments (June 30, 2004) at 22.

[206] Id. at 25.

[207] NRECA Comments (March 14, 2005) at 4.

[208] NRECA Comments (March 14, 2005) at 5; NRECA Comments (June 30, 2004) at 14.

[209] AEP Comments (June 30, 2004) at 12; Southern Comments (June 30, 2004) at 8.

[210] TAPS Comments (June 10, 2004) at 12-13; American Antitrust Comments (March 14, 2005) at 9.

context to the pivotal supplier screen by defining the market conditions or considering the pivotal supplier screen over multiple years, including any expected changes in supply and demand.[211] American Antitrust states that the pivotal supplier screen should not be used as it does not accurately capture the potential for a seller to exercise market power.[212] APPA states that the pivotal supplier screen should be based on monthly peaks instead of just a single annual peak month, the wholesale market share screen should be based on the minimum load and not the minimum peak load, the HHI concentration measure should be incorporated in the market share screens, the DPT threshold should be reduced to 1,800, and/or the market share threshold should be reduced to 15 percent.[213] EEI states that the native load proxy in the market share screen overstates the generation capacity available to the applicant for wholesale market sales and that instead of using the lowest seasonal daily peak demand to represent the supplier's native load obligation, alternative native load proxies should be considered.[214]

7. Dr. James B. Bushnell and American Antitrust comment that false positives may occur because the screens do not appropriately account for supply contracts and retail obligations, and that the market share screen needs to be altered if it is retained, adjusting

---

[211] Dr. Frayer Statement (January 27, 2005).

[212] American Antitrust Comments (March 14, 2005) at 6-7.

[213] APPA Comments (June 30, 2004) at 23.

[214] EEI Comments (March 14, 2005) at 7-8.

the threshold levels to consider market concentration in unconcentrated, moderately concentrated, and highly concentrated markets as set forth in the horizontal merger guidelines.[215] Some state regulators state that the Commission should eliminate the prohibition on the use of forward-looking data.[216] Some commenters note that the Commission should look into administering the screens on a regional basis.[217]

(iv) Alternative Analysis

8. IOUs state that the Commission should adopt a regional approach to its assessment thereby promoting efficiency and consistency of data collection and analysis among the sellers.[218] PacifiCorp suggests that a permanent replacement for the interim screens should include a clearly defined regional market or markets for the West.[219] EEI proposes a contestable load analysis[220] under which a seller failing either of the indicative screens would be given the opportunity to file at the time of the application to

---

[215] Dr. Bushnell Comments (March 14, 2005) at 3; American Antitrust Comments (March 14, 2005) at 8.

[216] See, e.g., California Board Comments (March 14, 2005) at 5.

[217] EEI Comments (March 14, 2005) at 29-31; APPA and TAPS Comments (June 13, 2005) at 4.

[218] PacifiCorp Comments (June 30, 2004) at 4-5.

[219] PacifiCorp Comments (March 14, 2005) at 5.

[220] The contestable load analysis focuses on the historical relationship between the wholesale loads that were actually seeking supply alternatives (contestable loads) and the resources other than those of the control area operator that were available to serve those loads.

demonstrate that the seller does not have generation market power.[221] FTC argues that the contestable load analysis is not economically sound, suffers from substantial defects and should not be relied upon to assess horizontal market power, stating that it fails to consider price, contractual and legal restrictions, transmission discrimination and transmission constraints.[222] Some commenters[223] are opposed to a contestable load analysis because it is so loosely prescribed that it would almost surely result in non-comparable, inconsistent results in the hands of different sellers, that it would most likely understate sellers' market power and eliminate from the screens any means of measuring the potential for coordinated behavior.[224] APPA suggests adding an HHI/concentration screen, using different metrics to measure collusion risks, requiring the seller to conduct the pivotal supplier screen on a monthly basis, and lowering the HHI component of the DPT from 2,500 to 1,800.[225]

9. Several state regulators support the use of simulation models as a tool for detecting collusion among several market participants or inaccurate uncommitted

---

[221] EEI Comments (March 14, 2005) at 15.

[222] FTC Comments (January 18, 2006) at 1-11.

[223] APPA Comments (March 14, 2005) at 2; American Antitrust Comments (March 14, 2005).

[224] NRECA Comments (March 14, 2005) at 5.

[225] APPA Comments (March 16, 2005) at 3.

capacity calculations.[226] IOUs state that the Commission should not rely on market simulation models. APPA argues that simulation models may have a role, but the Commission should not make any such model its sole assessment tool.[227] Dr. Bushnell states that the Commission should consider the use of an oligopoly simulation model, which would use a residual demand curve to test the market power of a given firm, which can be very useful in detecting potential market power with data requirements no more extensive than what is required for the screens.[228] Dr. Frayer argues that the Commission should also consider pricing behavior in its analysis, use a residual demand analysis, that the DPT should be refined to describe the market concentration of the capacity that would be price-setting, and should consider the hypothetical monopolist or "SSNIP" test.[229]

b. Procedural Issues

10. APPA and NRECA state that the Commission should allow intervenors more time to review and analyze the information and screen results provided by sellers and more time to submit rebuttal evidence such as their own DPT.[230] They suggest that the Commission allow 60 days for comments on the market screen analyses and the DPT and

---

[226] See, e.g., California Commission Comments (March 14, 2005) at 4.

[227] APPA Comments (June 30, 2004) at 18.

[228] Dr. Bushnell Comments (June 30, 2004) at 3.

[229] Dr. Frayer Comments (January 27, 2005) at 8-10.

[230] APPA Comments (March 14, 2005) at 22.

add that the Commission should require the regular reporting of generation and transmission data needed to perform the screens.[231] Tractebel states that sellers should be required to submit filings in standard formats so that the filings are easily comparable.[232] APPA states that too much data is designated as Critical Energy Information Infrastructure (CEII).[233] PacifiCorp argues that the Commission should allow each affiliate to pass or fail the screens on its own, without being aggregated with the other affiliates.[234]

11. Intergen states that the burden should be on sellers to prove that there is some compelling reason, such as reliability, to permit the seller to hold market-based rate authority or to provide appropriate remedial action to address any problems that may arise.[235] Forest & Paper expresses concern about false negatives produced by the indicative screens, and states that the rebuttable presumption improperly shifts the burden of proof from the seller to intervenors who may lack access to confidential data and the necessary resources to conduct elaborate and detailed market power studies.[236]

---

231 NRECA Comments (June 30, 2004) at 6.

232 Tractebel Comments (January 26, 2005) at 3.

233 APPA and TAPS Comments (March 16, 2005) at 3.

234 PacifiCorp Comments (June 30, 2004) at 5.

235 Intergen Comments (July 1, 2004) at 2.

236 Forest & Paper Comments (June 30, 2004) at 5, 7-8.

2. Vertical Market Power (Transmission and Other Barriers to Entry)

12. The Commission at the June 9, 2004 and December 7, 2004 technical conferences considered the issue of whether the Commission's pro forma OATT adequately mitigates transmission market power, as well as other proposals to identify and mitigate transmission market power. Specifically, the Commission examined the definition of transmission market power, how transmission market power could be used to foreclose competition, impact consumer and power supplier interests, how to differentiate between the exercise of transmission market power and legitimate reliability-driven denial of access, and other methods to screen for transmission market power and mitigate or eliminate transmission market power. The technical conference also addressed issues related to what other barriers to entry the Commission should consider in evaluating applications for market-based rate authority. Specifically, the conference discussed the effect that the lack of competition in fuel or other inputs could have on possible entry into the generation business, possible monopolization of future generating sites, and potential financial constraints such as competitors' creditworthiness or access to capital, that the Commission should consider in evaluating applications for market-based rate authority. After the technical conference, the Commission requested written comments from all interested parties.

a. Transmission

13. Several IOUs, including Duke, Southern, and FirstEnergy, assert that the OATT and various other rules are sufficient to mitigate transmission market power and that the

Commission should continue to rely on these unless there is substantial evidence that suggests widespread non-compliance/systemic violation of these standards.[237] MidAmerican asserts that if transmission limitations are restricting access to competitive supplies, this will be reflected in the Commission's current market power screens.[238] In addition, Cinergy suggests that the Commission retain the presumption that transmission-owning sellers do not possess transmission market power if the seller has an OATT on file or the seller's transmission is under the control of an ISO or RTO.[239] Cinergy also states that if some form of discrimination occurs in violation of the terms of open access transmission service, this is best addressed in the context of the OATT.[240]

14. Conversely, several other commenters state that the OATT is not sufficient to mitigate transmission market power and offer suggestions to help alleviate transmission market power, including the following:

a. Promoting best available transmission practices

b. Independent regional structures

c. Transmission planning and expansion and a reduction in congestion

d. Continuing to develop capacity markets

---

[237] See, e.g., Southern Comments (January, 1, 2005) at 12; Duke Comments (January 1, 2005) at 2; FirstEnergy Comments (January 21, 2005) at 6.

[238] MidAmerican Comments (January 21, 2005) at 13.

[239] Cinergy Comments (March 14, 2005) at 18.

[240] Id. at 18-19.

e. Requiring transmission owners to plan and construct the system as required by the OATT's requirements

f. Requiring transmission owners to interconnect with others

g. Clarifying rollover rights

h. Tying the grant of market-based rate authority to the willingness of the transmission owner to make upgrades and jointly plan with network customers.[241]

15. Similarly, several commenters identify the following transmission-related issues as barriers to entry:[242]

a. Transmission constraints

b. Transmission service denials

c. Interconnection and transmission discrimination

d. Transmission planning and expansion

e. Withholding transmission capacity through thermal loading calculations and operational practices.

f. Monopsony power

g. Customer foreclosure, which prevents the customer from being able to reach additional sources of power

h. Allocation of all firm transmission rights to the incumbent IOUs

---

[241] See, e.g., EPSA Comments (January 21, 2005) at 8-10; Mayflower Comments (January 21, 2005) at 12; TAPS and Midwest Municipal Transmission Written Statement (December 7, 2004) at 9; Transcript, December 7, 2004 at 28 (Boston Pacific); Transcript December 7, 2004 at 25 (NRECA); TAPS Comments (January 21, 2005) at 3.

[242] Transcript, June 9, 2004 at 62-63 (Dr. Hilke); Transcript, June 9, 2004 at 180 (Calpine); Transcript, December 7, 2004 at 14-18 (TAPS and Midwest Municipal Transmission); Transcript, June 9, 2004 at 108-114 (EPSA); Transcript, June 9, 2004 at 89 (Boston Pacific).

16. Calpine and PSEG state that the Commission may wish to consider applying a presumption that if a seller requests market-based rate authority and is not a member of an RTO or an ISO, it is has transmission market power.[243] Calpine asserts that the mere existence of an OATT is not sufficient to ensure that a vertically integrated utility cannot exercise transmission market power but that ceding control of transmission functions to an ISO or RTO or having its transmission market power mitigated by having its OASIS administered by an independent entity mitigates its transmission market power.[244]

17. EEI states that effective wholesale competition needs a robust and reliable transmission infrastructure[245] and further that fair and open access to transmission in non-RTO markets can be achieved through state and Commission efforts, such as independent transmission administrators, or transmission companies, and market monitors.[246] Dr. John Hilke (Dr. Hilke) similarly suggests that the Commission use membership in an approved and fully operating RTO or ISO as its initial transmission market power screen in evaluating market-based rate applications.[247] National Grid encourages the Commission to continue to expand its ongoing efforts to promote independent

[243] Calpine Comments (June 30, 2004) at 7; PSEG Comments (June 30, 2004) at 8.

[244] Id. at 3, 8.

[245] EEI Comments (January 21, 2005) at 7.

[246] Id. at 5.

[247] Transcript, December 7, 2004 at 10 (Dr. Hilke).

transmission.[248] The California Commission also supports the establishment of an independent market monitor in all transmission markets and further states that proposed transmission upgrades for potential discrimination in the siting of new or additional facilities should be examined. East Texas Coop states that where transmission market power exists, market-based rate authority must be revoked unless the utility turns its planning functions over to an independent entity.[249] PacifiCorp suggests that any additional measures the Commission imposes to mitigate transmission market power must apply to all transmission owners, not just those seeking market-based rate authority.[250]

18. Midwest Stand-Alone Transmission and Midwest Municipal Transmission state that structural solutions, such as the formation of stand-alone transmission companies and/or joint transmission systems, should be encouraged.[251] East Texas Coop agrees that stand-alone transmission companies are a promising structural remedy.[252]

---

[248] National Grid Comments (June 30, 2004) at 4.

[249] East Texas Coop Comments (January 21, 2005) at 7.

[250] PacifiCorp Comments (January 21, 2005) at 2, 8.

[251] Midwest Stand-Alone Transmission Comments (January 21, 2005) at 9; Midwest Municipal Transmission Comments (December 7, 2004) at 10; Midwest Stand-Alone Transmission Written Statement (December 13, 2004) at 4.

[252] East Texas Coop Comments (January 21, 2005) at 15.

19. APPA argues there should be better enforcement of the Network Integration Transmission Service portion of the OATT, as well as increased diversification of ownership of the transmission system, and that market-based rate authorizations of such dominant transmission providers should be conditioned upon their participation in an inclusive regional transmission planning process.[253]

20. FirstEnergy, EEI, and Joint Consumer Advocates state that there is a need for the construction of new transmission facilities and that the Commission should focus on ways to encourage investment in new energy infrastructure as a way of easing congestion, perhaps through an RTO.[254] National Grid advises the Commission to consider the expansion of the capability of the transmission grid as the best long-term solution to uncompetitive market conditions in generation.[255]

21. Xcel argues that the OATT should be modified to clarify and facilitate joint planning activities.[256] Dr. Benjamin Hobbs states that to address the challenges of transmission planning in wholesale power market environments, a transmission benefits methodology can be developed, such as the California ISO's Transmission Economic

---

[253] APPA Comments (January 21, 2005) at 2; APPA Written Statement (December 7, 2004) at 3, 7.

[254] FirstEnergy Comments (January 21, 2005) at 9; EEI Presentation (December 8, 2004) at 5; Joint Consumer Advocates Comments (January 21, 2005) at 5.

[255] National Grid Comments (June 30, 2004) at 3.

[256] Xcel Comments (January 21, 2005) at 7.

Assessment Methodology, which is a set of economic and risk analysis procedures that attempt to respond to the requirements of the new planning environment by explicitly quantifying the market power mitigation benefits of reinforcements.[257] APPA states that the Commission should encourage transmission providers to offer their network customers the opportunity to jointly own transmission facilities.[258] NRECA states that the Commission should develop transmission market power screens and consider making incremental changes to the OATT to better mitigate transmission market power.[259]

22. TDU Systems state that the OATT has been insufficient to mitigate the exercise of transmission market power and state that addressing the problem of transmission constraints is critical to a long-term structural solution to wholesale electricity market power problems.[260]

23. Midwest Municipal Transmission also comments that the Commission should further deny market-based rate authority to transmission owners that have not remedied congestion.[261] TAPS further asserts that where there is a lack of available transmission

---

[257] Dr. Hobbs Presentation (December 7, 2004) at 1.

[258] APPA Comments (January 1, 2005) at 2.

[259] NRECA Comments (January 21, 2005) at 4.

[260] TDUs Comments (June 30, 2004) at 10-12.

[261] Midwest Municipal Transmission Comments (December 7, 2004) at 11.

capacity (ATC), market-based rates should not be allowed.[262] Mayflower argues that a monopoly provider has market power and should be given the opportunity to rebut the presumption of market power by showing they have successfully implemented or emulated competitive markets.[263]

b. <u>Other Barriers to Entry</u>

24. Most commenters favor continued examination of other barriers to entry as part of market-based rate authorization, although some also recommend various modifications to the scope of the analysis and methods for assessment.[264] EEI comments that the Commission has rightly focused on the ability of a seller to erect barriers, but that there is little evidence that barriers to entry are a major problem.[265] EPSA asserts that barriers to entry can have a large impact on the competitiveness of a market but that this is an area of the Commission's analysis that has not been well-litigated or well-explained and where the industry needs more guidance as to what it takes to satisfy this prong of the Commission's four-prong analysis.[266] APPA argues that the Commission's other barriers

---

[262] TAPS Comments (January 21, 2005) at 2.

[263] Mayflower Comments (January 21, 2005) at 7, 8.

[264] One commenter recommends consolidating and subsuming the existing four prongs into analyses focused on vertical and horizontal market power. American Antitrust Transcript (June 9-10, 2004) at 160.

[265] Transcript, June 9-10, 2004 at 51 (EEI).

[266] Transcript, June 9-10, 2004 at 117-118 (EPSA).

to entry analysis is inappropriately restricted to barriers the seller can create and that granting the privilege of market-based rate authority should depend upon evaluating the existing entry barriers regardless of who created them.[267] TAPS argues that state-created legal barriers are an effective barrier to entry, citing restrictions governing the municipalities to which the Florida Municipal Power Agency (FMPA) can sell and in which time period, which TAPS states also has the effect of preventing FMPA from being an "anchor tenant" for merchant generation.[268]

25. Some commenters suggest that the Commission consider other barriers to entry that have not been previously considered. Bates White and American Antitrust propose that the Commission consider monopsony power as a barrier to entry. They state that a dominant buyer in a market can exercise monopsony power by refusing to buy from rivals; a rival will not enter the market if there is no demand for its output.[269] Mr. David S. Portnoy suggests that counterparty credit terms for transactions can serve as a barrier to entry because sellers with lower credit quality may only be able to sell in short-term markets because of credit demands from counterparties, which are not uniform.[270] Also,

---

[267] Transcript, June 9-10, 2004 at 137 (TAPS); Transcript, June 9-10, 2004 at 34 (APPA).

[268] Id.

[269] Transcript, June 9-10, 2004 at 9 (Bates White); Transcript, June 9-10, 2004 at 162 (American Antitrust).

[270] David S. Portnoy Comments (January 21, 2005) at 3-4.

Mayflower notes that the requirement that some IPPs post credit as a condition of transacting raises barriers to entry concerns.[271]

26. Several commenters offer recommendations for the assessment criteria for the other barriers to entry prong as it relates to defining the relevant market for a market power analysis. American Antitrust encourages the Commission to consider the guidelines approach employed by the DOJ/FTC 1992 Merger Guidelines,[272] which considers market share, ease of entry, and countervailing efficiencies. It submits that adopting more consistent guidelines would ease controversy over control area versus load pocket versus regional market analysis tension by introducing correct metrics for assessing participation in the market including time differentiated products and defining product markets.[273] EPSA states that to the extent that the native load exemption is included in the generation market power analysis, the opportunities for erecting barriers to entry are heightened.[274]

27. Others propose ways to detect when a barrier to entry has been raised and ways to initially screen for other barriers to entry. Calpine proposes that to detect whether a

---

[271] Mayflower LP Comments (January 21, 2005) at 37.

[272] US Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, 57 FR 41,552 (1992), revised, 4 Trade Reg. Rep. (CCH) ¶ 13,104 (April 8, 1997).

[273] Transcript, June 9-10, 2004 at 166-167 (American Antitrust).

[274] Transcript, June 9-10, 2004 at 118 (EPSA).

utility's access to the best generating sites constitutes an improper barrier to entry, the Commission can evaluate whether the utility provided a site to an affiliate at terms and conditions that are significantly different or cheaper than what one would expect them to provide to third parties.[275] More broadly, Dr. Hilke states that ISO/RTO membership and compliance with generation connection standards should be part of the initial screen for barriers to entry.[276]

3. Affiliate Abuse

a. Sales Restrictions

28. In connection with the January 27 and 28, 2005 technical conference, the Commission asked whether its current regulations and enforcement are adequate to address affiliate abuse and whether there are other factors the Commission should consider when granting market-based rate authority. Among other things, the Commission asked what the focus of the its affiliate abuse policies should be (protecting competition in the wholesale market; wholesale captive customers only; or wholesale and retail captive customers); whether the Edgar criteria are effective in mitigating and preventing affiliate abuse; and whether competitive solicitations are a feasible and reasonable means to ensure a level playing field.

---

[275] Transcript December 7, 2004 at 182 (Calpine).

[276] Transcript, December 7, 2004 at 12 (Dr. Hilke).

29. Some members of the industry, including Harquahala, the California Commission, and PacifiCorp suggest that a competitive solicitation process is an effective and reliable way to ensure there is no affiliate preference in the market.[277] Several IOUs assert that the Commission's existing affiliate abuse protection standards, including the Edgar standard, are sufficient to prevent affiliate abuse.[278] Harquahala moreover argues that all transactions, whether cost-based or market-based, should be held to the Edgar standard. Conversely, EEI, National Grid, and the Wisconsin Commission express general opposition towards the Commission requiring competitive solicitations and state that the Commission should consider state-approved alternatives to competitive solicitations and should continue to allow other approaches such as state or regional resource planning that involves public and merchant suppliers' participation.[279]

30. The FTC and the Maryland Commission assert that an independent market monitor or evaluator is imperative to a competitive environment.[280] Similarly, several commenters state that separate independent review by a regional or local monitor on an

---

[277] See, e.g., Harquahala Comments (January 21, 2005) at 2-3; California Commission Comments (March 14, 2005) at 3-4; PacifiCorp Comments (June 30, 2004) at 12.

[278] See, e.g., Southern Comments (March 14, 2005) at 7-10; Constellation Comments (March 14, 2005) at 23-25.

[279] See, e.g., EEI Comments (March 15, 2005) at 7-8; National Grid Comments (June 30, 2004) at 6-7; Transcript, January 28, 2005 at 14-16 (Wisconsin Commission).

[280] See, e.g., FTC Comments (July 16, 2004) at 15; Transcript, January 28, 2005 at 136-137 (Maryland Commission).

ongoing basis would yield the best results, and that it is the best way to ensure that a market participant is not exercising market power or engaging in affiliate abuse.[281] The FTC recognizes that the Commission likely will adopt a number of policies regarding protection against affiliate abuse and the role of an independent monitor. Accordingly it argues that the Commission may want to include compliance with any newly adopted policies regarding affiliate abuse as a prerequisite to passing the affiliate abuse screen. It further asserts that a utility with a record of violations of any of these policies should again bear the burden of proof that it passes the affiliate abuse prong.[282]

31. Dr. DeRamus asserts that the Commission has embarked down the right road in its approach to analyzing generation market power by setting up indicative screens that are used to simply establish a "rebuttable presumption" of market power, or lack thereof. He states that it is a procedural device that appropriately balances the competing demands for accuracy and expediency and ultimately suggests that the Commission follow a similar "rebuttable presumption" approach with respect to affiliate abuse.[283] EEI, however, opposes the creation of a rebuttable presumption of affiliate abuse if a seller is vertically integrated with ownership and control of transmission, there is no fully functioning RTO, there is significant lower-cost capacity from competing generators

---

[281] See, e.g., Transcript, January 28, 2005 at 122-123 (Independent Energy Producers); Montana Commission Comments (March 14, 2005) at 3.

[282] FTC Comments (July 16, 2004) at 15.

[283] Transcript, January 28, 2005 at 23-24, 26, 29, and 31 (Dr. DeRamus).

within the seller's control area, the seller continues to dispatch higher cost generation, and intervenors have complained.[284]

32. National Grid, EEI, and the Wisconsin Commission suggest that the state should have primary jurisdiction over affiliate abuse.[285] PacifiCorp similarly states that the Commission should review an affiliate transaction under the Edgar standard only when the applicable state commission declines to review the transaction or lacks the jurisdiction to do so.[286] Southern asserts that the Commission should not interfere with state jurisdiction over resource adequacy. Southern further argues that issuing resource adequacy guidelines on a federal level would also be improper because it would likely fail to take into account significant regional differences and particular retail needs.[287] Several industry regulators also believe that the Commission should focus on protecting captive wholesale customers instead of retail customers.

33. APPA and TAPS assert that competitive markets will aid the Commission in addressing affiliate abuse/self-dealing concerns because a consumer can readily choose a

---

[284] See, e.g., EEI Comments (March 15, 2005) at 9.

[285] See, e.g., National Grid Comments (June 30, 2004) at 6-7; EEI Comments (June 30, 2004) at 12, 25, and 27-31;and Transcript, January 28, 2005 at 14 and 16 (Robert Garvin).

[286] PacifiCorp Comments (June 30, 2004) at 12.

[287] Southern Comments (March 14, 2005) at 15-16.

supplier other than the one engaged in abusive behavior if the market is competitive.[288] PJM Industrial Consumers however argue that affiliate abuse can exist even within a competitive marketplace. They give examples of what they contend constitutes abuse occurring even where each participant's ability to sell to its affiliate is based on the fact that the price is tied to a relevant locational marginal price and they stress that the Commission should not just assume these prices are just and reasonable.[289] Ameren asserts that if the Commission were to adopt policies that place affiliates at a competitive disadvantage relative to non-affiliated entities, it would harm the consumers and competition.[290] Southern and EEI state that a utility's purchasing and dispatch activities are unrelated to affiliate abuse considerations and, in fact, they are unrelated to the Commission's market-based rate analysis because these activities involve a utility's purchases, not its sales.[291]

34. Many similar comments and arguments were received in Docket No. PL04-6-000, which addressed solicitation processes for public utilities.

b. Market-Based Rate Code of Conduct

---

[288] APPA and TAPS Comments (June 30, 2004) at 20-21.

[289] PJM Industrial Consumers Comments (January 21, 2005) at 25-27.

[290] Transcript, January 28, 2005 at 8-10 (Ameren).

[291] See, e.g., Southern Comments (March 14, 2005) at 17-20; EEI Comments (March 15, 2005) at 10.

35. In connection with the January 27 and 28, 2005 technical conference, the Commission asked, among other things, whether the code of conduct aids in preventing affiliate abuse, whether past waivers of the code of conduct have led to instances of affiliate abuse, and whether the code of conduct should contain additional provisions. Steve Corneli described the code of conduct as important in aligning market participants' interests with competitive results.[292] Dr. DeRamus urged that an applicant should not be able to "define away" the problem of affiliate abuse by implicitly or explicitly restricting its code of conduct[293] and called for a "searching inquiry" by the Commission to assess whether an applicant's specific code of conduct within the context of the applicant's business structure and practices will be effective in preventing affiliate abuse. Allen Freifeld said that exemptions from codes of conduct granted by the Commission on the basis of a retail rate freeze being in place at the time of the application may be harmful to the long-term development of markets.[294] EPSA notes that the existence of a corporate code of conduct is insufficient and does not eradicate the possibility of affiliate abuse.[295] Mr. Frame notes that when safeguards for customers, such as retail choice and rate

---

[292] Transcript, January 28, 2005 at 151 (Corneli). Similarly, Mr. Alan Kelly's comments noted the importance of the code of conduct in ensuring that affiliated generators or marketers do not receive preferential access to transmission information. Transcript, January 28, 2005 at 6 (Alan Kelley).

[293] Transcript, January 28, 2005 at 23-24 (Dr. DeRamus).

[294] Transcript, January 28, 2005 at 148-49 (Allen Freifeld).

[295] EPSA Comments (March 14, 2005) at 10.

freezes of wholesale customer protection, are in place "the need for a code of conduct or strict prohibition of utility-affiliate interaction becomes superfluous."[296]

5. Mitigation

36. The Commission examined issues relating to mitigation as part of the June 9, 2004 and January 27-28, 2005 technical conferences held in this proceeding. Among the issues discussed at the technical conferences were whether the current mitigation for horizontal market power was sufficient and what other methods the Commission could employ to mitigate horizontal market power. The technical conference also considered ways to mitigate vertical market power, among other things.

37. APPA and TAPS urge the Commission to stand firm and not to retreat from its findings regarding the need for the cost-based remedy, note that the mere existence of an RTO does not eliminate the need for cost-based rates, and argue that the Commission should mitigate the market and not the individual seller.[297] Calpine states that the Commission should not allow those who fail the screens to propose their own mitigation measures, and Forest & Paper suggests that the Commission take a more definitive and comprehensive approach in prescribing mitigation measures when sellers fail the screens

---

[296] Rodney Frame Comments (March 14, 2005) at 10.

[297] APPA Comments (June 30, 2004) at 16-17.

and DPT.[298] Xcel agrees with the appropriateness of establishing caps based on nearby markets where it can be demonstrated that the seller does not have market power, supports the limitation of mitigation only to wholesale customers that are load-serving entities in the relevant market, and opposes the suggestion of imposing an obligation to serve.[299] EEI argues that the price mitigation should emulate competitive markets and not regulated markets and that such price mitigation would avoid the economic distortions that would be created by cost-based mitigation.[300] Morgan Stanley argues that the Commission should require sellers to adopt integrated remedies that address all potential channels through which the seller could exercise market power and that the Commission should not allow sellers to adopt the Commission's default rate except as a last resort, since default rates do not address more subtle reasons for, or opportunities to exercise, market power.[301]

6. Implementation Process

38. PacifiCorp urges the Commission to adopt a regional approach to its assessment of generation market power. PacifiCorp's regional approach would identify regional

[298] Calpine Comments (June 30, 2004) at 11; Forest & Paper Comments (June 30, 2004) at 14.

[299] Xcel Comments (March 14, 2005) at 2-3.

[300] EEI Comments (March 14, 2005) at 18-19.

[301] Morgan Stanley Comments (March 14, 2005) at 9-10.

markets and evaluate the potential for market power within such regional markets. It states that such a regional approach would promote efficiency and consistency of data collection and analysis among the applicants.[302] While EEI supports retention of the control area as the default market, it states that it would support a regional approach option for suppliers voluntarily to submit a consolidated application covering a given market. According to EEI, the primary potential advantage of using a regional market approach would be the cost savings resulting from certifying an entire regional market at one time versus continuing the certification process on an individual supplier basis.[303] APPA and TAPS suggest that the Commission synchronize consideration of renewals for a specified geographic region, such as a regional reliability council. Among the benefits they cite for requiring applicants to simultaneously produce data for the region are improved quality and availability of data and development of a more complete picture of the market in which the applicants compete. They suggest that further streamlining could come from consolidation of reauthorizations of affiliated sellers. APPA and TAPS note that a regional approach does not relieve the Commission of its obligations to make a fact-based inquiry regarding a specific seller's potential to exercise market power.[304]

---

[302] PacifiCorp Comments (June 30, 2004) at 4-5.

[303] EEI Comments (March 14, 2005) at 24, 29-31.

[304] APPA and TAPS Comments (March 14, 2005) at 40-42.