UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF
AMERICAN PUBLIC POWER ASSOCIATION AND
TRANSMISSION ACCESS POLICY STUDY GROUP

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On May 19, 2006, the Commission issued a Notice of Proposed Rulemaking ("NOPR") in this ongoing proceeding examining the Commission's standards for reviewing and authorizing market-based rate ("MBR") sales by public utilities pursuant to Section 205 of the Federal Power Act.[1] The NOPR proposes to codify and make changes to the Commission's standards for MBR authorization (hereafter "MBR Standards"), including use of Market Share and Pivotal Supplier Screens ("Screens") and, in cases where a seller fails one or both of the Screens, a Delivered Price Test ("DPT") with thresholds adapted for MBR reviews. The NOPR also proposes to re-cast the Screens/DPT as the "horizontal market power test," examine transmission market power and entry barriers as part of a "vertical market power test," and to codify conditions relating to affiliate abuse. On the procedural front, the NOPR would relieve certain small sellers from the requirement of filing a triennial update (so called "Category 1" sellers) while instituting regional MBR triennial reviews for "Category 2" sellers. With respect

[1] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Notice of Proposed Rulemaking, 71 Fed. Reg. 33,102 (June 7, 2006), IV F.E.R.C. Stat. & Regs. ¶ 32,602 (to be codified at 18 C.F.R. pt. 35) (hereafter "NOPR").

to mitigation for sellers found to possess market power (or who accept the presumption of market power upon failing the Screens), the NOPR examines current polices for pricing short-term (less than one year), cost-based power sales. It also inquires about the need to require cost-based sales within a seller's control area where it is found to have market power and the need to revoke MBR authority outside the home control area of a seller found to have market power.

The American Public Power Association ("APPA") and the Transmission Access Policy Study Group ("TAPS") support many aspects of the NOPR. In particular, the procedural reforms should make the MBR program more manageable for the Commission, more "user-friendly" for market participants (especially Category 1 sellers), and should improve the quality of the Commission's MBR review by providing a richer, more consistent data base upon which to make MBR decisions. As a means to ensure that cost-based mitigation of market power is meaningful and practically available, APPA and TAPS also recommend adoption of the must-offer, cost-based sales obligation within a seller's home control area after the Commission has found that it has market power (or the seller accepts the presumption). Serious consideration must also be given to revoking or conditioning such seller's MBR authority outside the home control area as an incentive for such sellers to take steps necessary to mitigate market power on a long-term basis through structural changes (*e.g.*, transmission construction).

At the same time, APPA and TAPS are concerned that some of the NOPR's proposals, such as the upward adjustment in the size of the native load proxy for performing the Market Share Screen, will weaken the MBR Standards, increase the risk of "false negatives" and ultimately injure the wholesale consumers the Commission is duty bound to protect. APPA and TAPS present their comments below on the NOPR's many questions and urge adoption of a final rule that takes account of their comments.

EXECUTIVE SUMMARY

- The Commission's obligation to base its market-based rate determinations on "empirical proof" that "existing competition would ensure that the actual price is just and reasonable," *Farmers Union Central Exchange, Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984), requires the Commission to:

    - Apply the MBR Standards meaningfully by fully considering relevant evidence presented and not merely mechanistically crunching numbers through the Screens/DPT, *see* Part I below;

    - Define geographic markets based upon facts, such as transmission constraints, and not assume that geographic markets are co-extensive with RTO footprints or utility control areas, *see* Part I below;

    - Define product markets based upon the actual needs of consumers, such as long-term, load-following service, rather than based upon administrative expediency, *see* Part I below;

    - Consider historical and forward-looking evidence, whether presented by applicants or intervenors, and insist upon the filing of a DPT if a seller fails the Screens and seeks to rebut the presumption of market power. *See* Part I below.

- The Commission's MBR standards as developed and as applied must err on the side of caution due to the greater risk of market power exercise in electricity markets than in other industries. In electricity markets, firms with relatively small market shares can exercise market power because of key structural characteristics: the composition of firms' supply portfolios and a market's supply curve; the tendency of organized, bid-based markets in particular towards collusive bidding and pricing; the barriers to entry and exit in electricity markets; and the role of Locational Marginal Pricing ("LMP") in accentuating market power, including the market power of vertically integrated incumbents. The Commission must consider alternative analyses that highlight market power issues not revealed by the screens or the DPT. *See* Part II.A. below.

- The Commission should clarify that where a public utility selling under an MBR tariff knowingly or intentionally exercises market power, it violates its tariff and the Commission's regulations, and will be subject to the Commission's remedial authority, such as disgorgement of unjust profits. *See* Part II.B. below.

- The Commission should eliminate the exemption from MBR review for generation built after July 9, 1996 because such generation can exercise market power, especially in load pockets. *See* III.A. below.

- The Commission should adopt the proposed categorization of sellers as “Category 1” or “Category 2” but should preserve its right to require a seller that would otherwise qualify for Category 1 to file a triennial review where the Commission finds that such a seller poses market power risks (for example, because it is located in a load pocket). *See* Part III.B. below.

- The Commission should adopt the proposed regional review process for triennial updates to improve the evidentiary foundation of its MBR decisions. However, it should also provide intervenors with sufficient time, *e.g.*, 60 days, to respond to the regional filings of Category 2 sellers, given the larger amount of data to be analyzed and the need to prepare multiple comments contemporaneously. *See* Part III.C. below.

- The proposed pro forma MBR tariff will enhance clarity and transparency, and should be used as well by all members of a corporate family. *See* Part III.D.1 below.

- A uniform MBR reporting format should improve the consistency of the MBR reviews. *See* Part III.D.2 below.

- Using seasonal capacity ratings may be acceptable if done on a consistent basis and if intervenors have access to and can use necessary data. *See* Part III.E below.

- The Commission should establish a process to allow market participants to make an advance, single Critical Energy Infrastructure Information (“CEII”) request applicable to all public utilities scheduled for a regional review. *See* Part III.F. below.

- There is a clear need for a must-offer obligation applied to public utilities that relinquish or lose MBR authorization in their “home” control areas. The Commission’s substantial conditioning and remedial authority supports the imposition of such an obligation. However, the sales obligation can be limited to purchasers serving loads that sink in the home control area. *See* IV.A. below.

- The Commission may also need to revoke or condition a public utility’s MBR authorization outside of its home control area (and not just in the first tier) to remedy undue discrimination and to encourage the public utility to undertake structural mitigation that will address market power on long-term basis. *See* Part IV.B. below.

- Cost-based rates set to mitigate market power must be truly cost-based and should not be disguised market-based rates, as is typically the case with “up to” pricing. Short-term sales should be made based upon incremental cost plus a 10% margin or based upon traditional split-savings formulas. Sales of a week or more but less than a year should reflect the cost of the units providing the service. Long-term sales must be at rolled-in, average embedded cost. *See* Part IV.C below.

- Cost-based rates provide necessary immediate mitigation in the face of market power, but the Commission should also pursue structural mitigation (*e.g.*, capacity sales, transmission expansion, joint transmission ownership) to help develop a long-term infrastructure the supports competitive markets. *See* Part IV.D. below.

- The Commission should clarify that the simultaneous transmission import capability ("SIL") study should not show as available for reservation by third parties any Transmission Reliability Margin ("TRM") set aside or, to the extent actually reserved, any Capacity Benefit Margin ("CBM"). In any case, unreserved CBM must be modeled as available on a non-firm basis only. The SIL study should not model as available to the market transfer capability reserved by third parties on a long-term basis, because the capacity that could otherwise be imported using the reservation will appear in the third parties' own capacity shares. *See* Part V. below.

- The requirement that geographic market determinations be fact-based demands that the Commission examine whether the actual geographic market is smaller or larger than a utility's control area for non-RTO applicants. Among the factors the Commission should consider regarding the size of the geographic market is the existence of joint transmission planning and coordinated construction that is in fact resulting in expanded transmission facilities and thus broader trading markets. *See* Part VI. below.

- The presumption of the RTO footprint as the default geographic market must be truly rebuttable, including rebuttals based upon evidence that the RTO itself treats an area as a separate market (for example, as reflected in LMP price separation or the application of mitigation measures). LMP pricing in RTO markets only accentuates the role of transmission constraints in creating market power and causes regions to fragment into sub-markets; hence, it does not eliminate the need to define geographic markets as smaller than the RTO footprint. *See* Part VII.A. below.

- The Commission should not assume that RTO mitigation suffices to mitigate the market power indicated by the screens/DPT. There must be meaningful verification that such mitigation, even if claimed sufficient, does in fact mitigate the market power. Most RTO mitigation is far less protective of consumers than the Commission's default, cost-based mitigation and permits significant amounts of market power exercise. *See* Part VII.B. below.

- To measure whether sellers could be pivotal at peaks other than the annual peak, the Pivotal Supplier Screen should be performed using monthly peaks. *See* Part VIII.A. below.

- The proposed upward adjustment in the native load proxy for the Market Share Screen is unprincipled and aggravates flaws in the current proxy represented by the minimum native load peak for the season. If the Commission does not adjust the proxy downward to capture all the capacity available to compete in the wholesale market at some time, it should at least not change the current proxy. *See* Part VIII.B. below.

- The Market Share Screen should be performed once with a SIL study that includes non-firm transmission and another time with a SIL study that considers only firm transmission availability. The firm transmission run of the Screen is needed so that the Commission examines competitive conditions in markets for long-term capacity and other products that require firm transmission. *See* Part VIII.C. below.

- The Commission is correct to assign capacity to a seller for purposes of running the Screens/DPT where the seller can affect the ability of the capacity to reach the relevant market. However, because the inquiry is inherently fact-based, the seller should support its claims regarding lack of control over capacity with reference to specific contractual provisions and by submitting the relevant contract. *See* Part VIII.D. below.

- For purposes of the DPT, the market concentration threshold should be 1800 HHI [Herfindahl-Hirschman Index], not 2500 HHI, consistent with standard antitrust analysis and the Commission's merger policy. *See* Part VIII.E. below.

- For purposes of the vertical market power test, it is too early to tell whether the OATT, as modified in Docket No. RM05-25-000,[2] will mitigate transmission market power. The determination must await the outcome of the OATT NOPR in that docket. In any case, the Commission's determinations in the OATT NOPR proceeding must be reflected in the MBR NOPR proceeding. *See* Part IX.A. below.

- Revocation of MBR authority for violations of the OATT should be considered in appropriate cases, but the standard should be whether the OATT violation was "material," that is, denies customers the just, reasonable and non-discriminatory and comparable transmission service that is essential to mitigating transmission market power, rather than the proposed "nexus" standard. *See* Part IX.B. below.

- Entry barriers are not created by the seller alone. Entry conditions and barriers, regardless of origin, need to be considered in the horizontal generation market power analysis, as well as part of the vertical market power test. *See* Part X.A. below.

- The Commission should not codify the specific entry barriers that it will consider given the ever-changing nature of electricity markets. In addition, even if sellers do not have to address interstate gas transportation as part of the vertical market power test, intervenors should not be precluded from raising the seller's position in the gas transportation market as a potential entry barrier. *See* Part X.B. below.

- The proposed entry barriers affirmation should be signed and affirmed by a senior corporate official. *See* Part X.C. below.

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[2] *Preventing Undue Discrimination and Preference in Transmission Service*, 71 Fed. Reg. 32,636, 32,658-59 (proposed June 6, 2006), IV F.E.R.C. Stat. & Regs. ¶ 32,603, at 32,678-79, PP 148-54 (to be codified at 18 C.F.R. pts. 35 and 37), *corrected*, 71 Fed. Reg. 37,109 (June 29, 2006).

- The Commission properly proposes codification of the anti-affiliate abuse conditions so that violations of those conditions become violations of the tariff and Commission regulations. For purposes of affiliate abuse, conditions should apply to sellers with wholesale transmission customers and to third party energy/asset managers of plants. *See* Part XI. below.

- The Commission should require change in status reporting for (1) extended or repeated outages of key transmission and generation facilities that significantly affect transmission constraints, (2) a seller's execution of an agreement that provides it control over whether capacity reaches a market, and (3) a seller's position in fuel transportation. *See* Part XII. below.

- The Commission should not depart from its existing policies regarding market-based rates for ancillary services, and should be particularly careful when examining market-based rate proposals for sales into RTO markets, because the locational characteristics of most ancillary services increase the likelihood that sellers will be able to exercise market power. *See* Part XIII. below.

INTERESTS OF APPA AND TAPS

APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power systems provide over 16 percent of all kilowatt-hour ("kWh") sales to ultimate customers, and do business in every state except Hawaii. Approximately 1,840 of these systems are cities and municipal governments that currently own and control the day-to-day operation of their electric utility systems. Public power systems own about 10 percent of the nation's electric generating capacity, but purchase nearly 70 percent of the power used to serve their ultimate consumers. Because of their heavy reliance on purchases from regional wholesale power markets to obtain the power supplies they need to serve their loads, they have a vital interest in the Commission's MBR policies and procedures.

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[3] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members have long been concerned about structural changes in the electricity and natural gas industries that could adversely affect competition, rates or regulation, or could expose consumers to harms from unmitigated market power. TAPS has commented on nearly all of the Commission's major rulemakings and policy inquiries involving the electricity industry over the past decade.

APPA and TAPS have been active participants in this NOPR proceeding regarding the Commission's MBR program, Docket No. RM04-7-000. Representatives of APPA and/or TAPS have spoken at most of the Commission's technical conference in this proceeding.[4] APPA and TAPS have jointly and individually submitted comments as follow-up to these technical conferences, and several proposals in the current NOPR reflect their comments.

Communications regarding these comments should be directed to:

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[3] TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power Inc. Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

[4] June 9, 2004, Mark Hegedus on behalf of APPA and Fred Bryant on behalf of TAPS; Dec. 7, 2004, Anne Kimber on behalf of TAPS and Sue Kelly on behalf of APPA; Jan. 27, 2005, Mark Hegedus on behalf of TAPS and APPA; Jan. 28, 2005, Terry Huval on behalf of TAPS.

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COMMENTS

I. IN FULFILLING ITS RESPONSIBILITY TO ENSURE THAT MARKET-BASED RATES ARE JUST AND REASONABLE, THE COMMISSION CANNOT LIMIT THE RELEVANT MARKETS OR EVIDENCE THAT IT EXAMINES

The Commission is charged with ensuring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission… [are] just and reasonable…." 16 U.S.C. § 824d(a). Departures from cost-based rates must be strictly supervised. *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1530 (D.C. Cir. 1984). When a public utility proposes to depart from cost-based rates, the Commission must examine whether the entity has market power as "a means of carrying out its statutory mandate under the Federal Power Act to ensure 'just and reasonable' wholesale rates for electricity." *Cal. ex rel. Lockyer v. FERC,* 383 F.3d 1006, 1009 (9th Cir. 2004); *reh'g pending*. The Commission cannot permit market-based sales absent "empirical proof" that "existing competition would ensure that the actual price is just and reasonable." *Farmers Union*, 734 F.2d at 1510. "[U]ndocumented reliance on market forces" is insufficient to satisfy the Commission's regulatory responsibilities. *Id*. at 1508. It must find that a seller "lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation." *Lockyer*, 383 F.3d at 1013.

The Commission recognized these responsibilities in *AEP Power Marketing*:

> The FPA requires that all rates charged by public utilities for the transmission or sale for resale of electric energy be "just and reasonable." Where there is a competitive market, the Commission may rely on market-based rates in lieu of cost-of-service regulation to ensure that rates satisfy this requirement. Consistent with our precedent, the Commission authorizes sales of electric energy at market-based rates only if the seller and its affiliates do not have, or have adequately mitigated, market power in the generation and transmission of such energy, and cannot erect other barriers to entry by potential competitors. Thus, where a market-based rate applicant is found to have market power (*e.g.*, after reviewing an applicant's Delivered Price Test), it is incumbent upon the Commission either to reject such rates or to ensure that adequate mitigation measures are in place to ensure that the rates are just and reasonable.

AEP Power Mktg., Inc., 107 F.E.R.C. ¶ 61,018, P 144 (2004) (footnotes omitted) ("April 14 Order") (citing, among other cases, *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993)). Despite this recognition, the Commission's practice, especially when applying the Screens, has not been encouraging for intervenors who have sought to obtain Commission consideration of market-specific facts or of concerns that do not readily fit the Screens' rubrics.[5] The Commission cannot fulfill its obligations if it does not look at the facts on the ground.

The Commission must exercise its judgment and cannot simply plug data into the Screens/DPT and grant MBR authority based upon the resulting output. Thus, the Commission's proposed codification of the MBR Standards should not lead to mechanization of the Commission's MBR reviews. The goal of MBR review is to determine whether the applicant's market-based rates will be just and reasonable, not whether an applicant passes the Screens/DPT. APPA and TAPS believe the MBR Standards will provide the Commission with substantial evidence and analysis upon which it can make a decision about the justness and reasonableness of a seller's MBR authority, but agree with the Commission that neither the Screens nor the DPT can be treated as definitive.[6] Other relevant evidence, including evidence that may not fit neatly in the MBR Standards, must be considered.

Relevant markets present an example of where mechanization has already overtaken the Commission's obligation to make a fact-based determination regarding the justness and reasonableness of a seller's MBR authority. For example, while in the April 14 Order the Commission declared that defining the RTO footprint as the default relevant geographic market would be a rebuttable presumption,[7] in practice that presumption appears irrebuttable, even where an RTO market monitor designates an area as a load pocket geographically separate (in an electrical sense) from the remainder of the

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[5] *E.g.*, *PPL Montana, LLC*, 115 F.E.R.C. ¶ 61,204 (2006), *reh'g pending*; *Wisconsin Elec. Power Co.*, 110 F.E.R.C. ¶ 61,340, *reh'g denied*, 111 F.E.R.C. ¶ 61,361 (2005).

[6] *AEP Power Mktg.*, 107 F.E.R.C. ¶ 61,018 at PP 70-71.

[7] *AEP Power Mktg., Inc.*, 108 F.E.R.C. ¶ 61,026, P 177 (2004) ("July 8 Rehearing Order").

market.[8] On the product market side, the Screens/DPT pre-define relevant product markets largely based upon capacity that is supplying energy in a few snapshots of specific hours. However, if a buyer needs a particular kind of service, *e.g.*, round-the-clock load-following service on a long-term, firm basis, an IPP with single plant will not be in a position to supply the service. However, that IPP would likely show up as competing capacity in the Screens/DPT. The Commission cannot refuse to look at evidence relevant to whether suppliers are truly in a possible position to compete to provide a needed service.[9]

Similarly, the Commission's assessment of product markets cannot be limited to the hour or season analyzed by the Screens/DPT. Capacity available during those windows may not be available to supply customers needing to purchase power supply on a long-term basis. In *AEP Power Marketing*, 107 F.E.R.C. ¶ 61,018 at P 155, the Commission correctly recognized the need for such long-term products:

> Here we are noting that, in instances where we have found the potential for market power, long-term markets have not necessarily been shown to be inherently competitive. Although buyers do have more alternatives in long-term markets (including in certain circumstances building a new generating facility) than they would in short-term markets, we recognize that there are impediments to those alternatives. As noted by APPA's witness, Dr. Kirsch, there are a number of reasons why market participants do not have the option of building capacity at a competitive cost, including lumpy generation investment, insufficient

[8] *See, e.g.*, *Wisconsin Elec. Power Co.*, 110 F.E.R.C. ¶ 61,340, *reh'g denied*, 111 F.E.R.C. ¶ 61,361 (2005).

[9] *See, e.g.*, *Maine Pub. Utils. Comm'n v. FERC*, No. 05-1001, 2006 U.S. App. LEXIS 16445, *24 (D.C. Cir. 2006) (Commission must consider relevant factors).

For example, the Commission should examine a Market Share Screen or HHI presented by an intervenor that considers as potential sellers only those who could provide firm, load-following requirements services. *See* Horizontal Merger Guidelines, § 1.31 ("The Agency's identification of firms that participate in the relevant market begins with all firms that currently produce or sell in the relevant market.")

> transmission access, and insufficient access to fuels.[151] Further, depending upon the facts and circumstances, a new generating facility is not always a comparable or feasible alternative to a long-term purchase. As such, the theoretical ability to undertake such construction does not, per se, mitigate the ability to exercise market power. Our reliance upon such a theoretical possibility could be an oversimplification which may fail to protect customers under many real facts and circumstances. Thus, in keeping with our obligation under the FPA to ensure that sellers not charge unjust and unreasonable wholesale rates, we will require mitigated applicants to file such long-term contracts and not transact under such contracts without first receiving Commission approval.
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> [151] See February 2004 Comments of APPA at Kirsch Affidavit at 5. The concern with "lumpy" investment is that an LSE with a specific capacity need may not be able to build a facility to match that need. If it is too small, then the LSE will still need to buy long-term capacity and energy. If it is too big, then the LSE will be "long" and need to sell the power and may not have any customers, or [may] not have any interest in being a seller.

Accordingly, the Commission must apply the Screens/DPT in a manner that provides evidence regarding competition to supply long-term products, such as load-following service, and consider evidence beyond the Screens/DPT submitted by intervenors where the Screens/DPT do not present an accurate picture of competition in such longer term markets.[10]

These concerns about mechanistic or inflexible assessment of seller market power underscore APPA and TAPS's support for the NOPR's proposal to examine both historical *and* forward-looking evidence. NOPR PP 63-64. While forward-looking

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[10] As discussed below in Part VIII.C., the Commission should require an additional run of the Market Share Screen that at least removes non-firm transmission capability (including CBM) from the SIL study to provide a picture of the market for products, including long-term bilateral contracts, that must be backed by firm transmission.

evidence will, in some cases, require the Commission to rely on projections about future market conditions, decision-makers, be they judges or regulators, do so all the time. Such forward-looking evidence is essential for MBR Standards that authorize a seller to make market-based sales three years into the future. It would be reasonable to set a limit on how far forward the evidence can look, *e.g.*, the 3-year duration of the MBR authorization, but the Commission's refusing to consider such evidence at all puts its decision-making in a vacuum.

A clear example of where such evidence should be considered is expiration of long-term contracts. There is no reason not to require applicants to reflect the capacity freed up by a long-term contract that expires during the MBR authorization period sought in the applicant's MBR filing.[11] Such evidence would not be speculative, because the expiration date would be established by the contract itself.[12] Nor should the applicant be allowed to assume that the capacity will continue to be committed to a particular buyer, given that in a competitive market a buyer should be free to change suppliers at the end of a contract.

The Commission should clarify two issues regarding the evidence used to perform the Screens/DPT. First, the Commission "propose[s] 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,

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[11] The NOPR (at P 64) states that "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." Adjustments for the seller's expiring contracts or plant retirements, for example, should be reflected by the seller itself in its application. The seller is in the best position to know the amount of capacity associated with such events, and can simply model them in its MBR submission.

[12] *See, e.g.*, *Okl. Gas & Elec. Co.*, 105 F.E.R.C. ¶ 61,297, P 33 (2003) (expiration of long-term contract within a year was a known and measurable change).

provides all workpapers in support, and documents the source data." NOPR P 63. The Commission should not limit the ability to propose such adjustments to applicants; intervenors must also have the ability propose adjustments to the Screens/DPT to ensure their meaningful participation.[13] Second, in noting that the seller or intervenors may present historical evidence regarding whether a seller does or does not have market power, NOPR P 19, the Commission should clarify that the submission of such data does not relieve the seller of the obligation to submit a DPT if the seller chooses to try to rebut a presumption of market power associated with failure of one or both Screens. In other words, additional data and evidence should supplement, not replace, the DPT.

II. THE COMMISSION MUST REMAIN VIGILANT AGAINST POTENTIAL MARKET POWER EXERCISE

A. The Commission's Decisions Regarding Market-Based Rates Should Account for Challenges to Achieving Competitive Electricity Markets

Electricity markets exhibit a number of characteristics that make market power exercise more likely, including where the size of a firm or the number of firms might otherwise suggest that the market should be competitive.[14] In assessing a seller's eligibility for MBR authority, the Commission must apply MBR Standards that take account of these market power risks. For example, in developing and applying the Screens/DPT the Commission should choose thresholds that err on the side of caution

[13] While some intervenors may have the resources to present full-fledged alternative calculations of the Screens/DPT, others may not. APPA and TAPS understand that the Commission itself is able to re-run the Screens/DPT based upon adjustments proposed by intervenors. However, if the Commission does not have this capability, it should so state and require applicants to re-run the Screens/DPT based upon intervenor-proposed adjustments that the Commission concludes are known and measurable.

[14] Besides the characteristics discussed here, others include the inability to store electricity and the current absence of demand response sufficient to defeat anticompetitive price increases.

and recognize the Screens/DPT's limitations. It must consider claims that the Screens/DPT are not sufficiently probative of market power risks in particular cases and examine alternative analyses intervenors present. Failure to do so will leave the consumers the Commission is duty-bound to protect vulnerable to competitive harms.

One such characteristic unique to the electric power industry is the ability of a firm with even a modest market share to successfully exercise market power. Small firms that are seemingly non-dominant can withhold output and profitably raise prices. Economists Severin Borenstein and James Bushnell describe how, at certain times, a producer supplying a fairly small percent of the output can be pivotal in meeting the demand, and can therefore charge an extremely high price under the guise of "scarcity pricing:"[15]

> Unfortunately, it is easy to show that in such a situation [peak times] a firm of more than microscopic size can almost always do better than passively accepting these scarcity rents, attractive as they might be. By withholding a bit of its supply (or offering it to the market at an extremely high price), such a firm can drive the price still higher while losing little demand, and boost its profits. Thus, while it is easy to argue that volatile prices would be seen in even a perfectly competitive market with these attributes, it is equally easy to demonstrate that if firms of notable size are not exercising market power, they are doing so out of the goodness of their heart and against the interest of their shareholders.

A recent Ninth Circuit description of the California market echoes Bornstein and Bushnell's conclusion:

> As we now know, something happened on the way to the trading forum, and the best laid regulatory plans went

[15] Severin Borenstein & James Bushnell, *Electricity Restructuring: Deregulation or Reregulation?*, 23 Regulation 49 (2000).

> astray. The plan to establish a competitive market, while keeping the exercise of monopoly power in check, failed to account for energy economics and the sophistication of modern energy trading. As became clear in hindsight, even those who controlled a relatively small percentage of the market had sufficient market power to skew markets artificially. In short, the old assumptions, based on antitrust theory, that market power could not be exercised by those who possessed less than 20% of the market share proved inaccurate in California's energy market.

Pub. Utils. Comm'n of Cal. v. FERC, No. 01-71051, 2006 WL 2147552 *5 (9th Cir. 2006).[16]

A particular seller's supply portfolio and the supply curve of the market into which it sells contribute to the ability of small firms to profitably exercise market power. In its August 2002 Strawman on Market Metrics, the FERC Staff explained the need for some measure of structural incentives for withholding, where firms with units near the market clearing price (typically peaking units) hold large amounts of lower priced (typically baseload) capacity that could profit from economic withholding of the marginal units, or from physical withholding of small amounts of baseload capacity that would force the peaking units to set the marginal price.[17] In his article, *Analyzing Gas and Electricity Convergence Mergers: A Supply Curve is Worth a Thousand Words*, FERC Staffer David Hunger explained that "[e]stimating supply curves for the downstream electricity market gives analysts an additional tool for predicting future market

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[16] The court's description is not tied to California market rules in place in 2000-01.

[17] See "Strawman" Staff Discussion Paper on Market Metrics SMD Staff Conference on Market Monitoring, Docket No. RM01-12, *Remedying Undue Discrimination Through Open-Access Transmission Service and Standard Electricity Market Design*, at 12, *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=9567029 (last viewed Aug. 2, 2006).

outcomes."[18] Professor Darren Bush has noted that "[a] straight-up counting of capacity may not detect market power arising from a fuel curve problem."[19] Paul Joskow and Edward Kahn, when examining withholding behavior in California markets, recognized the importance of supply curves:[20]

> [W]hether withdrawing capacity is in the self-interest of a portfolio generator will depend critically upon the slope of the supply curve. It must be steep enough to result in MCPs sufficiently high so that the increase in profit on generation still tendered to the market more than offsets the profits lost on the capacity withdrawn.

Neither pivotal supplier nor concentration/market share metrics examine whether the seller's generation portfolio and the market's supply curve, taken together, provide ability and incentive to exercise market power. When analyzing both Screen and DPT results, the Commission thus needs to consider intervenor evidence focused on this source of market power.

A second unique characteristic of electricity markets is the ability of bidders to coordinate pricing to maintain prices above competitive levels, especially in organized markets where sellers frequently and regularly observe multi-bidder market interactions and the resulting outcomes and thus can develop strategies, including tacit joint strategies, to coordinate pricing. Electricity markets may well need a larger number of

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[18] David Hunger, *Analyzing Gas and Electric Convergence Mergers: A Supply Curve is Worth a Thousand Words*, 24:2 Journal of Regulatory Economics 161 (2003).

[19] "Comments of the American Public Power Association and the Transmission Access Policy Study Group," Market-Based Rates for Public Utilities, Docket No. RM04-7-000, at 48 (citing Bush Aff. ¶ 22) (filed Mar. 14, 2005) (eLibrary Accession No. 20050314-5175).

[20] Paul Joskow & Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricty Market During Summer 2000*: *The Final Word*, at 20 (Feb. 4, 2002), *available at* http://www.ksg.harvard.edu/hepg/Papers/Joskow-Kahn%20Final%20Word%20Feb2002.pdf (last viewed Aug. 2, 2006).

competitors to be workably competitive than conventional industrial organization theory would predict. Typical concentration analysis would predict that a market with a HHI of 1000, the bottom end of the moderately concentrated range, ought to be competitive. However, as economists from Carnegie Mellon Electricity Industry Center have observed, even in markets with a significant capacity surplus, 10 equally sized firms (*i.e.*, a market with an HHI of 1000) can quickly learn to raise prices to monopoly levels.[21] The risks of such coordinated pricing will grow in the future if mergers permitted by the repeal of PUHCA 1935 lead to just a handful of firms (*e.g.*, Exelon, Duke, Entergy, Southern, AEP, Dominion, Constellation, FPL and NRG) competing in the same regional markets across the U.S.

A third characteristic of electricity markets that makes them fertile ground for market power exercise is their non-contestability, due to the difficulties of entry and exit. In theory, competitive markets protect consumers from market power exercise, in part, by the threat of new investment, which can serve to restrain efforts to increase prices above competitive levels.[22] If a market is contestable, "even a monopolist must operate in an efficient manner and must earn no more than a normal rate of return on its capital investments," because of the competitive pressure exerted by potential entrants.[23] However, electricity markets, especially generation markets, are not necessarily

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[21] *See* Seth A. Blumsack, Jay Apt & Lester B. Lave, *Lessons from the Failure of U.S. Electricity Restructuring*, 19:2 Electricity J., Mar. 2006, at 15, 19.

[22] *See, e.g., Verizon Commc'ns Inc. v. Law Offices of Curtis V. Trinko*, 540 U.S. 398, 407-08 (2004).

[23] Robert A. Jablon, Mark S. Hegedus & Sean M. Flynn, *Dispelling Myths*: *A Real World Perspective on* Trinko, 50 Antitrust Bulletin 589, 601 (2005) (quoting William J. Baumol, John C. Panzar & Robert D. Willig, Contestable Markets and The Theory of Industry Structure 6 (1982)).

contestable, due to significant entry and exit costs.[24] Significant capital costs, siting difficulties and construction times and risks are well-known entry barriers in electricity markets. Equally important are barriers to exit, which can make it difficult to move an asset to another market if its deployment in the first market proves unprofitable.[25] For example, a generating facility involves not only the generation equipment itself, but also investment in transmission facilities to connect the new unit to the grid. Even though some limited portions of a plant, *e.g.*¸ the turbine, could be dismantled and used in another market, many parts of a plant, especially larger, base-load facilities, are designed for a specific use and location. Neither the plant nor the associated transmission facilities can simply be moved to another market.[26]

LMP market design magnifies these challenges. When transmission constraints bind, LMP effectively limits price competition in a load pocket to those sellers located within, or with transmission into, that pocket. The reduced universe of competitors increases the risks of successful market power exercise and accentuates its adverse consumer impacts when it occurs. Many LMP markets, for example, were superimposed on areas where incumbent sellers were and remain dominant and vertically integrated because of the lack of generation and transmission divestiture. Where high population density or other siting barriers make new entry even more difficult than usual, the market power concerns skyrocket.

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[24] *Id.* at 603-05; *see also* Comments submitted by Seth A. Blumsack, Jay Apt and Lester B. Lave to Electric Energy Market Competition Interagency Task Force, Docket No. AD05-17-000, at 1 (Nov. 18, 2005), *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10884315 (last viewed Aug. 2, 2006).

[25] Jablon, Hegedus & Flynn, *supra* note 23, at 605.

[26] *Id.*

These challenges should lead the Commission to err on the side of caution in assessing market power potential and to take very seriously intervenor claims that the Screens/DPT are not revealing a specific market power problem. As is discussed below Part VIII.E, the MBR test should not apply standards that are more permissive than in other industries, *e.g.*, the HHI threshold used to determine whether a seller passes the DPT. The Commission should be at least as concerned about false negatives as false positives, especially given the substantial shortcomings of after-the-fact remedies to market power exercise. The Commission should examine intervenor evidence on supply curves, including the possible risks of strategic bidding. It must ensure that cost-based rates designed to mitigate market power are truly cost-based, and not simply market-based rates masquerading as a "cost-based" up-to rate. And, the Commission should be more willing in meritorious cases to condition grants of MBR authority with structural conditions that "hardwire" the needed competitive incentives. Continued reliance solely on behavioral approaches to market mitigation can lead to resource intensive and often frustrating games of "cat and mouse."

B. Market Power Exercise Should Expose Sellers to Potential Liability for Violations of their MBR Tariffs

As part of the proposed codification of the MBR Standards and adoption of a pro forma MBR tariff, the Commission should clarify that a public utility with an MBR tariff shall not use the tariff to knowingly or intentionally exercise market power. While such a condition is inherent in a seller's MBR authorization, as explained below, the Commission would help those sellers who might otherwise "just not get it" if it included an explicit condition in the pro forma MBR tariff or in the MBR regulations.

The need for this clarification arises from the Commission's recent statements in repealing the Market Behavior Rules that both former Rule 2, as well as its replacement, 18 C.F.R. pt. 1c, focus "on actions or transactions intended to manipulate market prices, conditions, or rules, not the existence or use of market power absent some manipulation," which the Commission understands as requiring fraud or deceit.[27] The Commission also indicated that it would, in instances of non-manipulative market power exercise, consider forward-looking revocation or suspension of MBR authority.[28] However, while such forward-looking remedies must be in the Commission's tool box, they do not address the harm suffered by consumers as a result of intentional, non-manipulative market power exercise that has already occurred. Accordingly, the Commission should clarify that where a public utility selling under its MBR tariff knowingly or intentionally exercises market power, it violates its tariff and the Commission's regulations (not to mention the FPA) and will be subject to the Commission's remedial authority, such as disgorgement of unjust profits, for charging rates in violation of a rule, order, regulation or tariff on file.

MBR authority carries with it an obligation not to exercise market power, which arises directly from the Commission's authority to authorize market-based rates in the first instance:

> The use of market-based tariffs was first approved in the natural gas context, *see Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993), then as to wholesale sellers of electricity, *see Louisiana Energy and Power Authority v. FERC*, 141 F.3d 364, 365 (D.C. Cir. 1998). However, approval of such tariffs was conditioned on the existence of a competitive market. *Id.* Thus, market-based

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[27] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, "Order Denying Rehearing," 115 F.E.R.C. ¶ 61,053, P 18 (2006).

[28] *Id.* P 25.

> applications were approved only if FERC made a finding that "the seller and its affiliates [did] not have, or adequately [had] mitigated, market power." *Id.* The principle justifying this approach as "just and reasonable" was that "[i]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment." *Tejas Power Corp. v. FERC*, 285 908 F.2d 998, 1004 (D.C. Cir. 1990).

Lockyer, 383 F.3d at 1012-13 (footnote omitted). If a market-based rate is just and reasonable only if the seller does not have, or has adequately mitigated, market power, it follows that a rate that reflects market power exercise, especially where that exercise is intentional or knowing, is by definition not just and reasonable. Even if market-based rates are just and reasonable, sales at prices reflecting the MBR seller's market power exercise are not and thus violate the MBR tariff and the FPA. As the Commission has stated: "In a market-based rate regime, this means that public utility sellers will not be permitted to exercise market power or take anti-competitive actions that may increase market prices and that the Commission will take appropriate remedial steps."[29] In other words, MBR authorization does not include permission to charge rates that reflect market power exercise or are not otherwise constrained by competition. *Lockyer*, 383 F.3d at 1012-13.

The Commission must ensure that MBR sellers are complying with their tariffs by charging the authorized, just and reasonable rate. The Commission's ability to authorize market-based rates is tied to its continued oversight of the rates actually charged to

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[29] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, "Order Seeking Comments on Proposed Revisions to Market-Based Rate Tariffs and Authorizations," 103 F.E.R.C. ¶ 61,349, P 21 (2003).

determine whether they are, in fact, just and reasonable. *Id.* at 1013. According to *Lockyer*: "The structure of the [MBR] tariff complie[s] with the FPA, so long as it [is] coupled with enforceable post-approval reporting that would enable FERC to determine whether the rates were 'just and reasonable' and whether market forces were truly determining the price." *Id.* at 1014.[30] The reporting requirement is not an academic exercise, but an integral part of the Commission's obligation to determine the appropriate remedy where the rate actually charged is unjust and unreasonable.

The *Lockyer* decision strongly affirms that where the MBR tariff is violated, the Commission has the authority to remedy the violation, including through refunds:

> FERC possesses broad remedial authority to address anti-competitive behavior. *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000). Indeed, in the past, FERC has ordered refunds in instances where utilities violated FPA § 205, either by violating the terms of an accepted rate, or by charging rates without first seeking approval under FPA § 205. In *The Washington Water Power Co.*, 83 FERC ¶ 61,282 (1998), FERC ordered profits disgorged because a regulated utility had violated posting requirements and conferred undue preferences on its marketing affiliate. ["]To do otherwise would allow companies to flout our regulations, and overcharge consumers with impunity." 24 FERC ¶ 61,199 at 61,461, *reh'g order*, 24 FERC ¶ 61,380, *reh'g denied*, 25 FERC ¶ 61,308 (1983).
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> Here, because the reporting requirements were an integral part of a market-based tariff that could pass legal muster, FERC cannot dismiss the requirements as mere punctilio. If the ability to monitor the market, or *gauge the "just and reasonable" nature of the rates is eliminated, then effective federal regulation is removed altogether*. Without the required filings, neither FERC nor any affected party may

[30] While *Lockyer* involved the Commission's failure to enforce reporting requirements, those reporting requirements exist not for their own sake but to permit the Commission to determine whether the market-based rates actually charged are just and reasonable.

> challenge the rate. Pragmatically, under such circumstances, there is no filed tariff in place at all. The power to order retroactive refunds when a company's non-compliance has been so egregious that it eviscerates the tariff is inherent in FERC's authority to approve a market-based tariff in the first instance. FERC may elect not to exercise its remedial discretion by requiring refunds, but it unquestionably has the power to do so. *In fact, if no retroactive refunds were legally available, then the refund mechanism under a market-based tariff would be illusory. Parties aggrieved by the illegal rate would have no FERC remedy, and the filed rate doctrine would preclude a direct action against the offending seller. That result does not comport with the underlying theory or the regulatory structure established by the FPA.*

Lockyer, 383 F.3d at 1015-16 (emphasis added). Moreover, if the Commission did not possess such remedial authority, it would not be able to approve market-based rates in the first instance: "If, on the other hand, we view the reporting requirements as integral to the tariff, *with implied enforcement mechanisms sufficient to provide substitute remedies for the obtaining of refunds for the imposition of unjust, unreasonable and discriminatory rates*, then a market-based tariff is permitted." *Id.* at 1016 (emphasis added). *See also CPUC*, No. 01-71051, 2006 WL 2147552 *14 (FPA § 309 provides FERC with "remedial authority to require that entities violating the Federal Power Act pay restitution for profits gained as a result of a statutory or tariff violation.").

Congress enacted FPA Sections 205 and 206, along with the rest of the FPA, because of concerns about the absence of "free and independent competition" in the power industry. *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975) (internal quotation mark omitted). Those concerns are even more acute in an era where the Commission's policy is to rely upon competitive markets to ensure that rates are just, reasonable and not unduly discriminatory or preferential. As the D.C. Circuit observed: "Of the

Commission's primary task there is no doubt, however, and that is to guard the consumer from exploitation by non-competitive electric power companies." *Id.* In enacting the Energy Policy Act of 2005, Congress did not repeal Sections 205, 206 or 309, nor did its adoption of Section 222's prohibition of market manipulation signal or direct that the Commission should retreat from its obligation and authority to enforce existing provisions. Rather, Section 222 is a new tool (not a substitute) for the Commission to address "exploitation by non-competitive power companies."[31]

A public utility that knowingly or intentionally exercises market power while selling under its MBR tariff, but whose conduct does not rise to a violation of Section 222 and 18 C.F.R. pt. 1c.2(a), should not be immune from a finding that it has violated the statutes, orders, rules, regulations or tariffs this Commission administers and thus should be subject to remedies, such as disgorgement of profits, for the violations. It would be a strange outcome indeed if a seller could face such remedies for failing to file a timely change in status report or triennial review, NOPR PP 97, 155, for violations of the affiliate abuse conditions, NOPR P 108, or for failing to file an electronic quarterly report ("EQR"), *see Lockyer*, 383 F.3d at 1015-16, but not if it exercised market power under the MBR tariff under which these obligations arise. Such an MBR regime would exalt form over substance, and leave consumers unguarded from exploitation at the hands of MBR sellers.

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[31] *See also* 151 CONG. REC. S7053 (daily ed. June 22, 2005) (statement of Sen. Bingaman) (directing the Commission to use its existing authority in addition to the new anti-market manipulation language).

III. THE COMMISSION SHOULD ADOPT MANY OF THE NOPR'S PROCEDURAL ADVANCES

A. The Commission Should Eliminate the Exemption from MBR Filing Requirements for New Generation

The Commission proposes to eliminate the current exemption, set forth at 18 C.F.R. § 35.27(a) for new generation capacity for which construction commenced on or after July 9, 1996, from the requirement to demonstrate a lack of generation market power. NOPR P 70. APPA and TAPS strongly support eliminating the exemption. The Commission correctly observes that over time, the exemption could result in all market participants being exempted as older generation is retired. NOPR P 69. However, even while the older generation is still being sold into the market, post-1996 generation can exercise market power. Concerns about market power associated with recently built generation may be most acute in load pockets where even a new plant may face inadequate competition due to transmission constraints. Under such circumstances, the seller could have market power, making MBR authority unlawful unless mitigated. *See* April 14 Order at P 40.

APPA and TAPS agree that eliminating the exemption will not impose significant new burdens or otherwise deter new entry. NOPR P 74. The Commission cites no evidence indicating that having to file for MBR authority chills new generation entry. The Commission also correctly points out that in many cases new entrants may qualify for an exemption from filing triennial updates, because they would be treated as "Category 1" sellers. NOPR P 72. In other cases, a new entrant could readily demonstrate that it qualifies for MBR authority by making simplifying assumptions, such as running the Pivotal Supplier and Market Share Screens assuming no import capacity or treating the host control area utility as the only other competitor. NOPR P 71. Under these simplifying assumptions, which would show less competition and enhance the seller's position in the market, the seller's passing of the Screens would provide additional assurance that MBR sales are permissible. Further, the current exemption already does not apply to the many sellers whose fleets contain both older and new generation. NOPR P 70. As result, the benefits of eliminating the exemption in terms of the Commission's mandate to ensure that rates for jurisdictional sellers are just and reasonable will far outweigh any added burdens.

B. The Proposed Triennial Update Obligations for Category 1 and Category 2 Sellers Make Sense and Should Be Adopted

The NOPR proposes to divide jurisdictional sellers into two categories for purposes of filing triennial reviews. Category 1 would include sellers, including power marketers and power producers, that (1) own 500 MW or less of generation capacity in the aggregate; (2) are not affiliated with a public utility having a franchised service territory; (3) do not own or control transmission facilities other than limited equipment needed to connect individual generating facilities to the transmission grid (or limited and discrete transmission facilities); and (4) do not present other vertical market power concerns. NOPR P 152. Category 1 sellers would not have to file triennial updates, but would have to file initially for MBR authority and would be subject to change in status reports under Order No. 652. They would also remain subject to ongoing monitoring by the Office of Enforcement. *Id.* Category 2 would include all sellers that did not qualify for Category 1; Category 2 sellers would file regularly scheduled triennial updates. NOPR P 153.

APPA and TAPS support the proposed categories and calibration of filing requirements based upon the likely market power risk a seller poses. As a general matter, smaller sellers and those that do not have captive customers or own/control transmission facilities should not raise serious market power concerns. The Commission should clarify, however, that it retains the ability to determine that a particular seller that might otherwise qualify for Category 1 must still adhere to the triennial update requirements. For example, a seller, while relatively small, may nonetheless have market power or be dominant in a particular load pocket created by transmission constraints. In such cases, the Commission should be able to revoke such a seller's exemption from the filing requirement. MBR authority remains a privilege, not a right.[32] In cases where the Commission has determined that particular seller has greater potential to exercise market power, the Commission must require periodic updates.

The NOPR also asks for comment "on the extent to which [independent and affiliated power marketers and power producers] 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." NOPR P 169. APPA and TAPS suggest that the Commission provide waivers to sellers that qualify for Category 1 (unless otherwise required to make triennial filings as discussed immediately above).[33] The Commission also asks about the orderly transition from market-based to cost-based rates and the role

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[32] *Enron Power Mktg., Inc.*, 106 F.E.R.C. ¶ 61,024, P 13 (2004).

[33] However, any such waivers should not exempt a holding company or service company from applicable reporting requirements under the Commission's PUHCA 2005 regulations.

that such waivers may play in making that transition more difficult. NOPR P 171. In view of the fact that Category 2 sellers are more likely than Category 1 sellers to lose MBR authority and find themselves subject to cost-based rates, not providing to the waiver for Category 2 sellers should address these transition concerns.

C. Regional Triennial Updates Should Improve MBR Review

Reflecting proposals that APPA, TAPS and others made, the NOPR "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." NOPR P 154. APPA and TAPS see numerous benefits from adopting this proposal.

One of the chief benefits involves data consistency and availability, as the NOPR (at P 154) recognizes. Regional proceedings provide a means to require applicants to simultaneously produce data for the region, thus allowing such data to be used to develop a more complete picture of the regional market. Such proceedings should provide an opportunity to ensure that generation units (*e.g.*, capacities, control) are modeled consistently. Transmission data from several adjacent systems would facilitate resolution of any transmission capacity discrepancies among operators of common transmission interfaces. Where they exist, ISOs/RTOs should provide market participants with the data needed to prepare the MBR tests in advance of the regional review. Having better data and a more complete picture of a region's market will help the Commission fulfill its obligations to ensure that MBR decisions are based on "empirical proof" that "existing competition would ensure that the actual price is just and reasonable." *Farmers Union*, 734 F.2d at 1510.

While MBR review can be coordinated on a regional basis, such an approach does not translate to the conclusion the relevant geographic market is that specific region. Proper competitive analysis requires that the Commission define the relevant geographic market based upon factual evidence, such as transmission constraints, control area boundaries, and trading patterns.[34] See Part VII.A below. A regional approach does not relieve the Commission of its obligations to make a fact-based inquiry regarding each specific seller's potential to exercise market power. For this reason, APPA and TAPS agree with the NOPR's proposal "to continue to make findings on an individual seller basis." NOPR P 154.

The Commission must also adjust the notice period for intervenors responding to the regional filings. According to Appendix B to the NOPR, Category 2 sellers "will file updated market power analyses within the filing period specified in the … schedule." The Commission apparently envisions permitting a seller to file at any time during a 30-day window for a particular region (for example, April 1-30, 2007 for sellers in the PJM footprint). For the Commission and market participants to have the benefit of the collective data that the regional filings should yield, it should measure the notice period for responding to the regional filings from the end of the filing period so that intervenors

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[34] Technical Conference on Market-Based Rates Rulemaking, Docket No. RM04-7-000 (Jan. 27, 2005) ("January 27 Technical Conference"). Tr. at 124:15-23 (Wroblewski) ("Using a regional approach makes sense if this means that FERC will examine all the applicants for market-based rate authority in a particular region at the same time. Doing so will allow FERC to properly delineate product and geographic markets within that particular region. If using a regional approach means using one geographic region as the geographic market, then I'd say this [is] no more accurate than using control areas as the geographic market for assessing market power."). *Accord* Tr. at 133 (Solomon).

will have as much of the filed data and analyses as possible when preparing their own responsive pleadings.

The NOPR asks whether the current 21-day period is sufficient. NOPR P 83. Because the triennial updates will not be initial Section 205 filings, the statutory 60-day action period will not apply, which makes a short, 21-day notice period unnecessary. In any event, a 21-day notice period for MBR triennial updates will not suffice. Because numerous sellers will file the triennial updates contemporaneously, intervenors should be given sufficient time to make meaningful use of the expanded body of information and to prepare multiple pleadings dealing with various sellers in the region simultaneously. In large regions such as MISO or PJM, it is easy to envision intervenors having to respond to many filings. At a minimum, the Commission should provide 60 days for the preparation of comments. The additional time should improve the quality of the analyses that the Commission receives from intervenors, which will accrue to the Commission's benefit.

Finally, adoption of the regional approach may provide the Commission with information and data to support development of a standardized, regional structural or simulation model so that the Commission can make its own, consistent judgments regarding MBR eligibility. A recent assessment of DPT analyses submitted by merger applicants revealed widely varying HHI results for the same utilities, whether the economists performing the DPT were the same or different people.[35] While the specific analysis examined the DPT submitted for merger filings, the use of the DPT for MBR

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[35] Diana Moss, *Electricity Mergers, Economic Analysis, and Consistency: Why FERC Needs to Change Its Approach*, AAI Working Paper 04-02, mimeo at 23-24; *available at* http://www.antitrustinstitute.org/recent2/348.cfm (last viewed Aug. 2, 2006).

analysis raises similar concerns.[36] As the author notes, "defining electricity markets is fraught with data, methodological, and modeling challenges."[37] The Commission's obligation to ensure that rates are just and reasonable requires that it work to overcome these challenges, and develop additional in-house capability to evaluate independently applicants' market analyses.

D. The NOPR's Proposals for Greater Uniformity Will Aid Both the Commission and Market Participants

1. A Pro Forma MBR Tariff, Including a Single Tariff for Members of a Corporate Family, Should Improve Transparency and Oversight

The NOPR proposes a pro forma MBR tariff for all sellers. It would also require that all members of a corporate family have a single MBR tariff, with all affiliates with MBR authority identified in the tariff. NOPR PP 161, 164. These proposals usefully address a number of recurring problems. One involves variations in MBR tariffs themselves, even within the same corporate family, which increase transaction costs by sowing potential confusion about applicable terms and conditions. A second difficulty involves the determination of exactly who is affiliated with whom, including when examining an MBR filing to ensure that all the capacity controlled by the seller and its affiliates is reported. The NOPR proposal sensibly brings order and clarity to these issues and should be adopted.

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[36] *Id.*, mimeo at 3.

[37] *Id*., mimeo at 26.

2. A Uniform Reporting Format Will Aid in Consistent Treatment of MBR Filings

The NOPR proposes “to require all sellers to submit the results of their indicative screen analysis in a uniform format to the maximum extent practicable,” and prescribes a format for doing so. NOPR P 65 and Appendix C. APPA and TAPS support this proposal. Additional uniformity should help all market participants, especially when assessing the filings of a number of public utilities as part of the proposed regional review process. The uniformity should also help the Commission analyze MBR filings on a consistent basis, thus increasing market participant confidence in those assessments.

E. Use of Seasonal Capacity Ratings May Be Acceptable if Used Consistently and the Data Are Readily Available to Intervenors

APPA and TAPS support in principle the NOPR’s proposal to allow sellers the option of using seasonal capacity instead of nameplate capacity, NOPR P 75, but have several concerns that the Commission should address before adopting the proposal. One concern involves the consistent use of such data. The NOPR states that the “seller must be consistent in its choice and use one capacity measure or the other measure of capacity ratings throughout the analysis.” NOPR P 75. The Commission should clarify that the seller must be consistent not only with the capacity ratings of its own generation, but all other sellers reflected in the analysis. In other words, if the seller uses seasonal capacity for its plants, it must do the same for all plants, regardless of ownership.

The Commission also says that it does not think that using seasonal capacity “will materially impact results.” *Id.* That would seem to be true so long as the seller is consistent regarding which data are used. However, APPA and TAPS are concerned about how the proposal would affect the proposed regional analyses if some sellers in a region use nameplate capacity and others use seasonal capacity. Thus, the Commission should require use of one or the other throughout a region so that the consistency benefits of the regional reviews are not diminished.

The NOPR also asks about the availability of such data. *Id.* While APPA and TAPS do not know if seasonal capacity data will be available for all of the capacity that needs to be reflected in the analysis, the Commission must ensure that all market participants have access to such data if it is used. Regardless of the kind of data used, the applicant must provide the data to intervenors. If the seller purchases that data from a commercial source, it should obtain permission to provide the data to intervenors at no additional charge to them and to allow intervenors to use the data in the proceeding regarding applicant's MBR authority.

F. The Commission Should Establish a Process for Market Participants to Request CEII In Advance of Regional Filings

APPA and TAPS appreciate the NOPR's inquiry into whether CEII designations remain a concern. NOPR P 83. The experience of APPA and TAPS members is that in some cases the party claiming CEII has agreed to provide the information to market participants subject to protective order, a process that consumes some of the preciously short time available to respond to an MBR filing. In cases where the CEII request process must be used, consultants working for market participants sometimes simply make assumptions in lieu of using the actual data because a CEII request generally takes weeks to process. Given the time required to obtain CEII authorization and the obvious advantage of having actual data in hand, the Commission should provide a process to allow interested market participants to obtain CEII authorization in advance of a region's triennial updates. Such authorization would apply to all sellers in the region where MBR authority is up for review and would necessitate that the requester file only one request.

IV. MITIGATION MUST BE MEANINGFUL

APPA and TAPS commend the Commission for examining several recurring issues related to cost-based mitigation. To remedy seller market power effectively, mitigation must have practical value to those in harm's way--the wholesale consumers who are unable to turn to suppliers other than the seller. While APPA and TAPS support a number of the cost-based mitigation proposals set forth in the NOPR, they also urge the Commission to use its substantial conditioning authority to move beyond cost-based rate mitigation when necessary. The Commission needs to develop mitigation strategies that promote structurally competitive markets, so that the Commission does not have to police them through cost-based pricing to ensure rates are just and reasonable.

A. The Commission Should Adopt a Must-Offer Requirement for Sellers Opting for Cost-Based Rate Mitigation

1. The Problem

As the NOPR describes (at P 145):

> [I]f 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.

Cost-based rates address only economic withholding; the seller remains free to physically withhold. The MBR seller, particularly one that also provides and controls transmission service and access, may respond to a cost-based rate requirement by refusing to sell in the home control area, especially if it has designs on weakening captive competitors in its footprint for subsequent acquisition. If that were to occur, customers would be denied access to needed power supply (a scenario only underscored by the market power findings leading to the seller's initial loss of MBR authority).

A seller's OATT, standing alone, does not remedy the problem. That the seller continues to dominate its home market is powerful evidence that the OATT is not sufficient to mitigate the seller's market power, simply because sufficient transmission capability is not available to obtain alternative power supplies. Even if, as a result of proposed reforms to the OATT, such a seller had a strengthened obligation to plan the transmission system to provide meaningful access to competing suppliers, the Commission should not conclude that the OATT alone suffices, given the time that it could take to construct sufficient transmission facilities to relieve all of the relevant bottlenecks. Thus, the Commission should adopt a must-offer obligation to ensure that cost-based mitigation is practically available to consumers in the home control area.

2. The Commission's Authority

The Commission's authority and responsibility to set standards for cost-based and market-based sales under Section 205 support the Commission's imposing a must-offer condition on a seller's cost-based and/or MBR tariff. Recent D.C. Circuit decisions strongly affirm the Commission's conditioning authority in the Section 205 context. In *California Independent System Operator Corp. v. FERC,* 372 F.3d 395 (D.C. Cir. 2004), the Court confirmed that if the California ISO did not meet FERC's conditions for qualification as an ISO, FERC need not approve it as one.

> If FERC concludes that CAISO lacks the independence or other necessary attributes to constitute an ISO for purposes of Order No. 888, then it need not approve CAISO as an ISO. ISO membership is not an end in itself;

> it is merely a method jurisdictional entities can use to comply with Order No. 888's mandate for those entities to file nondiscriminatory open access tariffs.… The Commission, in Order No. 888 and other rulings made pursuant thereto, has defined ISOs according to the terms it wishes. FERC has the authority not to accept something which it does not deem an ISO.

372 F.3d at 404. Likewise, market-based rates are not an end in themselves but are only one method public utilities can use to comply with Section 205's requirement for just and reasonable rates.

The court also specifically recognized the Commission's power to condition jurisdictional utility rate filings. *Id.* at 402 (citing *Central Iowa Power Coop. v. FERC*, 606 F.2d 1156 (D.C. Cir. 1979)). The D.C. Circuit's recent decision in *Maine PUC v. FERC*, Case No. 05-1001, 2006 WL 1788965 (D.C. Cir. Jun. 30, 2006) similarly stressed the Commission's substantial authority to condition Sections 205 rate filings. Where a seller files for authorization to sell at cost-based or market-based rates, the Commission's authority includes establishing the conditions under which those sale must occur.

Further, a refusal to sell wholesale power to customers captive to the seller's transmission system, particularly where the seller continues to sell off system, would constitute clear physical withholding, *i.e.*, market power exercise, and undue discrimination for which a remedy would be required.[38] In support of this remedial obligation, Section 309 gives the Commission authority "to perform any and all acts, and to…issue…such orders…as it may find necessary or appropriate to carry out the

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[38] 16 U.S.C. § 824e; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd New York v. FERC*, 535 U.S. 1 (2002).

provisions of th[e] [Act]."[39] A must-offer obligation would represent an appropriate use of that authority.[40]

Support for imposing such an obligation is found as well in the inability of wholesale customers to access alternative suppliers. The Commission has explained that an obligation to provide service under the FPA may "stem from the inability of the wholesale customer to obtain service from sources other than its current supplier. It is the absence of alternatives that affect the public interest."[41] Although Order No. 888 rejected a generic obligation for public utility sellers to continue wholesale sales past the expiration of the contract in question, the order explained that the FPA can impose an obligation to continue service on a case-by-case basis.[42] Where wholesale customers are unable to access supply from other than the dominant seller, a case-specific justification

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[39] 16 U.S.C. § 825h; *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 158 (D.C. Cir. 1967). *See Permian Basin Area Rate Cases*, 390 U.S. 747, 779-87 (1968) (decided under parallel Natural Gas Act provision).

[40] It is no objection to a must-offer obligation that the antitrust laws may not always impose a duty to deal. *See, e.g.*, *Trinko*, 540 U.S. 398, 415. The Commission enforces the FPA, not the Sherman Act.

[41] *Pacific Gas & Elec. Co.*, 44 F.E.R.C. ¶ 61,010, at 61,050-51, *reh'g denied*, 45 F.E.R.C. ¶ 61,061 (1988); *Florida Power & Light Co.*, 8 F.E.R.C. ¶ 61,121, at 61,448 (1979) (rejecting proposed tariff that would "eliminate the only practical source of base-load power or energy to competing utilities").

[42] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), *reprinted in* [1991-1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), *reprinted in* [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 61,688, 64,714 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248 at 62,110, *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998) ("we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis"); *see also* Order No. 888, 61 Fed. Reg. 21,540, 21,639 (May 10, 1996), *reprinted in* [1991-1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, at 31,805 & n.652 (1996) (explaining that although the Commission determined "not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers," "any party claiming to be aggrieved by a utility's alleged abuse of generation market power under a wholesale requirements contract can file a complaint with the Commission under section 206").

for the must-offer obligation exists. *See also* April 14 Order at P 154 ("to the extent an applicant is found to have market power and is not otherwise mitigated, we will require that long-term sales into the relevant market where the applicant has market power be priced at embedded cost-based rates.").

3. The Parameters of the Obligation

The NOPR raises a number of questions regarding the parameters of a must-offer obligation. NOPR P 146(b). APPA and TAPS suggest the following tailored parameters, guided by the Commission's correct conclusion in the April 14 Order (at P 154) regarding the need for cost-based mitigation to provide for short-term and long-term sales.[43]

- *Short-Term Sales*: The seller should offer short-term products (daily, hourly, weekly) out of capacity not used to serve firm and native load customers, as the NOPR (P 146(b)) suggests. The Commission should consider its proposal made in its 2001 order announcing the Supply Margin Assessment test ("SMA Order") as the posting mechanism by which the seller would make known the amount of power for sale.[44] That mechanism involved the seller's posting by noon (though APPA and TAPS recommend 8:00 a.m.) for the following trading day the uncommitted capacity (*i.e.*, generation in excess of each hourly projected peak load and minimum required operating reserves) for spot market sales in the relevant market.[45] The total amount available can be broken down into blocks, *e.g.*, 10 MW, corresponding to the incremental cost of the capacity supplying the energy.

  If the seller has no uncommitted capacity, it should take reasonable steps, such as redispatch of its resources with costs shared on a load ratio basis, to create transmission import capability for the captive customer(s) until transmission import or generation capacity becomes available. The Commission should also state that if the seller represents that it has no generation uncommitted capacity, but evidence (such as an EQR reflecting an off-system sale) shows that it did, the Commission will initiate an enforcement action under its anti-market manipulation rules.

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[43] APPA and TAPS address pricing issues in the Section IV.C. below.

[44] *AEP Power Mktg., Inc.*, 97 F.E.R.C. ¶ 61,219, at 61,972 (2001).

[45] *Id.* While the Commission originally proposed a noon posting time, APPA and TAPS understand that the availability determinations generally occur earlier.

- *Long-Term Sales*: If a seller holds MBR authority, the seller must offer those products that it is capable of providing and that captive LSE customers in its footprint need, whether short-term or long-term, and not just those it chooses to provide. The seller's market power exists largely because its transmission system (the condition of which it is responsible for) limits access to competing resources. It is reasonable to require the MBR seller to work with on-system customers to help them satisfy their power supply needs. In addition, the Commission found in the April 14 Order (at P 155) that in many cases customers will not be in a position to build for themselves but must look to the market to satisfy their needs. Thus, if the customer issues a request for proposals ("RFP") for power supplies, the seller should be obligated to respond based upon its capability at that time to do so. It would also be reasonable to require customers who may purchase under the must-offer obligation to issue RFPs to provide an opportunity for the market to respond.

  The kinds of products supplied should reflect those that a wholesale customer may need to reliably supply its retail customers, *e.g.*, load-following full or partial requirements service or unit power. If the seller and customer cannot agree on the rates, terms and conditions for such sales, the customer should be permitted to request the seller to file the unexecuted agreement with the Commission for its review and resolution of disputes

- *No Obligation to Build*; *Obligation to Offer Participation*: The seller would not be required to plan and build generation to satisfy the must-offer obligation or to respond to an RFP (though the seller would not be relieved of any independent obligations, such as nuclear plant license conditions, to plan and build for customer needs). However, to the extent the seller proposes to build generation to serve load in its home control area, it would be required to offer participation, either via ownership or capacity sales. Such a condition would partially mitigate the MBR seller's acknowledged generation market power in its home control area.

- *Must-Offer Obligation Limited to Service to Loads in the Home Control Area*:[46] In recognition of the fact that loads captive to the seller's market power in its control area do not have meaningful choices, the must-offer obligation would apply to those loads. In the case of a joint action agency ("JAA") with loads in multiple control areas, including the seller's, the JAA could purchase an amount under the must-offer obligation equivalent to the size of the JAA's load in the seller's control area and could integrate that purchase with its other resources to serve its total JAA load. The must-offer obligation would not extend to non-captive buyers who are simply looking to purchase cost-based power for export and sale at a higher price elsewhere. The seller would not be precluded from making such a sale, however.

[46] If the seller were not the balancing authority, the obligation would apply in its transmission service territory.

APPA and TAPS note that while in most cases applying the obligation to the seller's control area will suffice to cover potential harmed customers, there may be instances where a potentially harmed customer is not in the seller's control area but is in the seller's transmission service area. For example, there may be customers who either operate their own control area embedded in the seller's control area, or who are dynamically scheduled into another. In these cases the customers remain in the seller's transmission service area and are equally affected by the transmission constraints that contribute to the seller's market power. As a result, while referring to the obligation as applying to a seller's control area provides a convenient short-hand, the Commission must also apply the obligation to captive customers in the seller's transmission service area.

In light of the foregoing parameters, including restricting the must-offer obligation to loads in the seller's control area, APPA and TAPS do not believe the other parameters the Commission suggested are necessary and, in any event, find the parameters unclear and possibly difficult to implement. The NOPR (P 146(b)) asks "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?" The reference to a cost-based ceiling suggests that the open season would only be for products with duration of a week or more, or less than a year, which would not suffice to satisfy the range of customer power supply needs. Further, such a parameter would require the customer to project a year in advance its shorter term energy needs, which would be impossible in the case of unforeseen events. The open season also appears to convert the product to be offered from a short-term to a long-term one, which would presumably mean a different pricing approach. Thus, APPA and TAPS do not recommend that the Commission adopt the open season proposal, at least in its current form.

B. The Commission Should Consider Revoking or Conditioning MBR Authority Outside the Home Control Area on a Case-by-Case Basis

The NOPR inquires whether as an alternative to the must-offer obligation the Commission should revoke MBR authority not only in the home control area, but also in adjacent (first tier) control areas. NOPR P 146(c). While as explained below the Commission has the authority to extend revocation beyond the home control area, APPA and TAPS are concerned that such a remedy, at least absent the must-offer obligation, would not provide practical relief to customers within the seller's home control area. Specifically, it is not clear that an across-the-board revocation would necessarily prompt the seller to sell power in its home control area, even where such sales provided incremental revenues to it and its native load customers. Public power systems' long experience with certain recalcitrant, Commission-regulated public utilities teaches that it is not beyond the pale for some sellers to refuse to sell to obtain competitive advantage, such as takeover of a municipal system. *See generally Florida Power & Light Co.*, 8 F.E.R.C. ¶ 61,121 (1979). By contrast, the must-offer obligation will ensure that customers in the seller's home control area will have access to at least some power supply.

However, the Commission should not rule out across-the-board revocation or other conditions, in addition to the must-offer obligation. Revoking or conditioning

MBR authority beyond the home control area may be necessary to motivate the seller to undertake the kind of structural measures needed to mitigate its market power on a long-term basis, such as construction of transmission. The ultimate goal must remain creating structural competitive markets. The Commission clearly has the authority to revoke or condition MBR authority beyond the seller's home control area, both to ensure that rates are just and reasonable, 16 U.S.C. § 824d(a),[47] and to prevent and remedy undue discrimination. 16 U.S.C. § 824d(b).[48]

If the Commission adopts a policy to revoke or condition MBR authority beyond the home control area, the policy should not be limited to just the first-tier control area as the NOPR suggests (at P 146(c)). Rather, the revocation or conditions should apply to any market where the seller can use generation located in or originally delivered to its control area to sell outside the control area. Given Commission policies promoting broader markets, it is unrealistic to expect that the seller would not take advantage of sales opportunities beyond the first tier.

C. Pricing For Mitigation Sales Should Be Truly Cost-Based, Not MBR Sales in Disguise

As the NOPR observes, in the late 1980s the Commission began permitting greater flexibility in the pricing of cost-based rates, departing from more traditional "split the savings" or units "most likely" to participate formulas. NOPR PP 134, 140. APPA and TAPS are very concerned that if this flexibility is carried forward for pricing cost-

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[47] *Cf. Textile Workers Union of America v. Darlington Mfg. Co.*, 380 U.S. 263 (1965) (NLRB order upheld finding violation in plant closing following election of union bargaining agency while it did not close other plants).

[48] The Commission should also not exclude outside the control area remedies in appropriate cases for violations of the OATT or the anti-market manipulation rules.

based sales intended to mitigate market power, there will effectively be no mitigation at all, but rather market-based rates cruelly disguised as cost-based ones. The unsustainable situation created by this flexibility is illustrated by the Commission's discussion of discounting:

> 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.

NOPR P 143. The cost-based rates under consideration in this proceeding would be charged by sellers found to have (or who have accepted the presumption of) market power. The Commission should have no expectation that they would discount from a high "cost-based" cap to maximize revenues when they know that potential purchasers in the home control area have no realistic alternatives. Even if the flexibility the Commission would afford could be justified by an expectation that off-system purchasers could use their ability to buy elsewhere to bargain for a lower rate, that assumption does not apply where the cost-based rate is being used to mitigate market power.

The mitigated price must effectively remedy the seller's market power, not simply give the seller another means to exercise it. APPA and TAPS therefore support pricing for such mitigated sales on a more disciplined basis than has been the Commission's practice. In the April 14 Order (P 152), the Commission proposed that sales of less than a week occur at the seller's incremental cost plus 10%, correctly observing that:

> Absent market power, a generator would typically run if it had excess power and could cover its incremental costs plus some return. In addition, customers will be protected

> against any exercise of market power in spot markets in these circumstances because the mitigated applicant will not have an opportunity to charge excessive rates.

Alternatively, such sales could occur under the traditional "split-the-savings" methodology, which is equally consistent with the Commission's observation that "a generator would typically run if it had excess power and could cover its incremental costs plus some return." Such pricing successfully supported economy and coordination transactions for years, utilities know how to work with it, and the Commission proposed a similar approach in the SMA Order.[49]

With respect to sales with duration of a week or more but less than a year, the Commission quite successfully relied upon a methodology based upon the units most likely to provide the service, until it began allowing greater flexibility in setting "up to" rates. While the Commission expresses concerns about determining the units most likely to participate, the disputes more recently have arisen due to the high, "cost-based" caps utilities have developed under the Commission's policy of flexibility. For example, under the flexibility policy, the Commission allowed "up to" rates to reflect a utility's newest unit, even a nuclear unit. *See Illinois Power Co.*, 57 F.E.R.C. ¶ 61,213, at 61,699-700 (1991). However, it is untenable to assume that a seller would ramp up a nuclear plant to make a short-term sale. At least when setting cost-based mitigation rates, the Commission should insist upon a well-supported analysis of the units most likely to provide the service. Alternatively, the Commission's suggestion that such sales be priced

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[49] *AEP Power Mktg.*, 97 F.E.R.C. at 61,972.

on an average embedded cost basis would be acceptable and would avoid the need to make determinations about units most likely to run. NOPR P 140.[50]

APPA and TAPS do not support the NOPR's suggestion of a price "not tied to the cost of any particular seller but rather to a group of sellers." NOPR P 141. There is no assurance that the group rate would reflect the costs of the seller subject to mitigation. Further, selecting the group to establish the rate, and obtaining the necessary cost information for each one of them, could be extremely difficult and controversial.

While the NOPR proposes no changes in the pricing of long-term sales, APPA and TAPS reiterate their support for pricing such sales on an average, system embedded cost basis. Consistent with cases such as *Carolina Power & Light Co.*, 113 F.E.R.C. ¶ 61,130, P 27 (2005), and *AEP Power Marketing, Inc.*, 112 F.E.R.C. ¶ 61,047, P 25 (2005), the Commission should not depart from this policy.

Finally, APPA and TAPS support the current policy of requiring that sales in the geographic market where the seller has market power be cost-based, regardless of whether the sales sink in the seller's control area. *See* NOPR PP 147-49. A contrary policy would yield unlawful rates, because the seller would be making market-based sales in the market where it has market power (or is presumed to have it) even though it was found to have market power and had not mitigated it. April 14 Order at P 40. However, APPA and TAPS are not unsympathetic to concerns that marketers may look to buy low from the mitigated seller at the cost-based rate and sell high at a market rate

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[50] The Commission must also adhere to the principle that energy and demand charges be developed consistently. *See Florida Power & Light Co.*, 66 F.E.R.C. ¶ 61,227, at 61,532 (1994). The Commission should not tolerate rates reflecting demand charges based upon the seller's most costly capacity and energy charges, using its units with the highest operating costs.

outside of the seller's control area. To address this concern, the Commission could limit the must-offer obligation to sales that sink in the seller's control area, as discussed above (Part IV.A.3). If the seller wanted to make additional sales in its control area at the cost-based rate, it could do so, but would not be so obligated. Purchasers for loads outside of the seller's control area will presumably have other power supply options.

D. While Cost-Based Rates Provide Needed Interim Relief, the Commission's Should Promote Structural Remedies that Provide Long-Term Incentives for Competitive Markets

Absent a finding that a seller lacks market power or has mitigated it, the Commission must require cost-based rates to fulfill the FPA's commands. *Farmers Union*, 734 F.2d at 1502. However, cost-based rates do not achieve competitive wholesale markets. Ideally, wholesale customers should have a meaningful choice of suppliers whose costs are disciplined by competitive forces. That is unlikely to happen unless the Commission pursues structural changes in the markets where sellers are found to possess market power. Remedies focused on fostering structurally competitive markets will help to ensure that future consumer choices are more real than they are today.

As a longer term alternative to cost-based pricing and to remedy market power on a long-term basis, the Commission should pursue structural conditions.[51] "The authorization to sell power at market-based rates . . . – as opposed to traditional, cost-based rates – is a privilege, and granted if, and only if, the Commission determines that an applicant's use of such rates will be just and reasonable." *Enron Power Mktg., Inc.*,

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[51] Until such structural remedies are fully implemented, the seller will still need to sell at cost-based rates.

106 F.E.R.C. ¶ 61,024 at P 13.[52] Where a seller seeks the privilege to sell at market-based rates and where the Commission is pursuing its goal of regulation through reliance on competitive forces, the Commission's conditioning authority is at "zenith."[53] It must require cost-based rates to provide an immediate remedy to seller market power, but should encourage acceptance of conditions that ensure underlying competitive circumstances support future reliance upon market forces adequate to discipline rates.[54]

There are a number of conditions available to create competitive markets characterized by many buyers and many sellers. For example, the Commission can aid in increasing the number of sellers by encouraging diverse ownership and control of generation. If the record indicates that the seller holds a dominant position in the market, the Commission can condition the MBR authorization on the seller's taking steps to reduce its dominant position. The seller can put control of capacity necessary to address its dominance into the hands of third parties through sales of capacity, whether by selling the capacity outright (*i.e.*, divestiture) or turning control of that capacity over to a third party (*e.g.*, long-term contract with full-dispatch rights, auction of capacity rights, tolling agreements). The Commission has required such remedies in the merger context to address market power concerns. *See American Elec. Power Co.*, 90 F.E.R.C. ¶ 61,242,

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[52] *See generally, Pennsylvania Water & Power Co. v. FPC*, 343 U.S. 414, 418 (1952) ("A major purpose of the whole Act is to protect power consumers against excessive prices.").

[53] *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967). *See also Northern Natural Gas Co. v. FERC*, 785 F.2d 338, 341 (D.C. Cir. 1986).

[54] *Farmers Union*, 734 F.2d at 1509; *Interstate Natural Gas Ass'n v. FERC*, 285 F.3d 18, 34 (D.C. Cir. 2002) (relying upon Commission "monitoring and assurance of remedies in the event of insufficient competition, on which *Farmers Union* set great store"). *See also Revised Pub. Util. Filing Requirements*, 67 Fed. Reg. 31,044, 31,054 (May 8, 2002), III F.E.R.C. Stat. & Regs., ¶ 31,127, P 111 (2002), ("[T]he Commission's market-based rate findings do not absolve the Commission from its continuing responsibility to assure that rates are just and reasonable.").

order on reh'g, 91 F.E.R.C. ¶ 61,129, at 61,489 (2000) (capacity sale); *Allegheny Energy, Inc.*, 84 F.E.R.C. ¶ 61,223 (1998) (divestiture); *Exelon Corp.*, 112 F.E.R.C. ¶ 61,011 (2005) (divestiture and capacity sales). Similar remedies could be conditions to MBR authorization. The Commission could also impose a condition requiring the seller to invite market participants, especially wholesale customers who may be captive to the seller's transmission system, to participate in new generation projects.

In many cases, the dominant position of an MBR seller that also operates a transmission system in its home control area is attributable to the inadequacy of that transmission system, a situation that the seller itself may have contributed to by inadequately planning for the needs of network customers and eschewing efforts to develop regional solutions to transmission problems. If the presence of substantial and continuing transmission constraints in a dominant transmission provider's control area allow it to charge supra-competitive "market-based" rates for generation in its control area, it is appropriate for the Commission to require these constraints to be addressed, if it is going to allow that transmission provider to charge MBR. In such a case, the appropriate structural remedy is expanding transmission capacity, access and ownership to create a more robust grid that enables buyers and sellers to reach one another. The Commission should impose mitigating conditions on MBR authority to increase access to existing transmission facilities by customers in the MBR seller's control area subject to the seller's market power, as well as to expand their transmission access through rolled-in upgrades.

To use capacity on existing facilities to the fullest extent possible during the pendency of a transmission construction program, an MBR applicant that controls transmission should set aside capacity for use by wholesale customers trapped in the applicant's control area by transmission constraints, so that these customers can obtain access to alternative suppliers. If necessary, such capacity can be created through redispatch of the MBR seller's resources with costs shared on a load ratio basis, as a temporary remedy until new transmission is built.[55] Other solutions involving existing grid capacity include the MBR seller's making any CBM it has set aside available for use by wholesale captive transmission customers in the seller's control area.

Longer term solutions require transmission expansion so that the transmission grid can support willing buyers and sellers who wish to make deals. The Commission should enforce the OATT requirement (§ 28.2 and Preamble to Part III), as ultimately modified in the pending OATT NOPR, that the transmission owner plan the system to accommodate a network customer's existing and planned designated network resources. However, the Commission in appropriate cases should also tie the grant of MBR authority to a vertically-integrated transmission owner's demonstrated commitment to make specific transmission upgrades that would allow its wholesale customers cost-effective access to competitive alternatives. *Cf. Okl. Gas & Elec. Co.*, 108 F.E.R.C. ¶ 61,004 (construction of transmission "bridge" as remedy to market power concerns). It should tie the grant of MBR authority to the demonstrated willingness of such vertically-integrated transmission owners to jointly plan and construct transmission with their network customers, to participate with them in collaborative, open regional transmission planning processes, and to permit such customers to invest in the transmission system on

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[55] *See Okl. Gas & Elec. Co.*, 108 F.E.R.C. ¶ 61,004 (2004) (requiring redispatch until 600 MW transmission "bridge" was in place).

a comparable basis. Customer investments must be treated comparably to the transmission provider's own, through mechanisms such as transmission credits and recovery of costs through the transmission owner's revenue requirement.

V. TRANSMISSION CAPABILITY SHOULD BE BASED ON REALISTIC MARKET CONDITIONS

The NOPR proposes continued use of the simultaneous transmission import capability ("SIL") study prescribed in Appendix E of the April 14 Order for conducting the Screens/DPT. NOPR P 76.[56] Surprisingly, the NOPR's discussion of the SIL study does not mention the ongoing rulemaking involving revisions to the OATT, Docket No. RM05-25-000, including the practices to be used in calculating ATC, CBM, TRM and the like that will clearly affect the SIL study results. The OATT NOPR concludes that existing practices for calculating these measures are widely variable and therefore are unjust, unreasonable, unduly discriminatory and preferential. 71 Fed. Reg. at 32,658-59, IV F.E.R.C. Stat. & Regs. at PP 148-54. Given likely changes in its requirements for such practices, the Commission should not adopt a final rule in the MBR NOPR that does not reflect or is made subject to its determinations in the Final Rule on the OATT NOPR.

Further, because they are not mentioned in the MBR NOPR's discussion of the SIL study, APPA and TAPS urge the Commission to affirm its clarifications of Appendix

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[56] Appendix E of the April 14 Order states that "power flow cases should represent the [Transmission Providers] tariff provisions, the operational practices historically used, all reliability margins (TRM, CBM, counter flow, generating operating limits, operating reserves) existing during each peak, and all firm/network reservations held by applicant/affiliate resources during the most recent seasonal peaks." 107 F.E.R.C. ¶ 61,018, at 61,087. It further provides the power flow benchmark cases of historical monthly peaks should "reasonably simulate the historical conditions that were present including; facility/line deratings used to maintain capacity benefit margins (CBM) and transmission reliability (TRM/CBM), actual unit dispatch used to fulfill network and firm reservation obligation, the actual peak demand, generator operating limits opposed on all resources in real time, other limits/constraints imposed by the TP during the season peaks." *Id*.

E from the July 8 Rehearing Order. First, the Commission should affirm that TRM set asides should not be included in transmission capability. July 8 Rehearing Order at P 47. Second, the Commission should affirm that CBM set asides should be reflected in transmission capability as non-firm capability unless they are used for reliability during season peaks, in which case they should not be treated as part of import capability. *Id.* P 48.

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

VI. THE GEOGRAPHIC MARKET FOR NON-RTO AREAS SHOULD BE DETERMINED BASED ON FACTS

In non-RTO areas, the Commission proposes to continue using the seller's control area as the default geographic market, noting that designating a default geographic market provides a measure of certainty. NOPR P 51. While the control area provides a reasonable starting point, the Commission's obligation to base its MBR decisions on "empirical proof" requires reliance on specific facts that demonstrate whether the relevant geographic market should be the control area, or a smaller or larger area. The Commission's setting the geographic market question for hearing in the *Entergy* case drives home the point that the relevant market can be other than the default one.[57] The seller should therefore affirmatively address whether the geographic market should default to the control area or whether a smaller or larger area is appropriate, and support that result with evidence. Intervenors should also be allowed to introduce evidence regarding the question.

APPA and TAPS generally agree that the factors set forth by the Commission in the NOPR (PP 53-58) are reasonable, although they urge that the factors be non-exclusive and non-prescriptive. If the Commission becomes too rigid in the evidence it considers and how it considers the evidence, it will disserve market participants and fail to fulfill its FPA and Administrative Procedure Act ("APA") obligations. In addition to the factors the Commission has identified, APPA and TAPS suggest that a seller be allowed to point to any joint transmission planning and coordinated construction processes that are producing results, *i.e.*, getting transmission built that significantly expands customer access to the regional competitive market, as evidence that the relevant market should be larger than its own control area. A seller that is concretely advancing efforts to expand markets deserves to have that recognized, and those efforts should be apparent in the

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[57] *Entergy Servs., Inc.*, 111 F.E.R.C. ¶ 61,507 (2005).

Screen/DPT results. Likewise, a seller that is not undertaking such efforts should live with the consequences of the resulting smaller market.

APPA and TAPS also urge that the factors be used equitably. At one point the NOPR states that 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." NOPR P 53. However, the discussion that follows (PP 53-58) focuses on whether the relevant market should be expanded. Only at the end of P 58 does the Commission ask whether to "apply the same criteria when determining whether the geographic market is smaller than the default geographic market." The Commission should not bias the question in favor of an expanded geographic market but must remain equally open to the geographic market being smaller than the default depending on the facts.

VII. APPLICATION OF THE MBR TESTS IN RTO AREAS MUST ALSO YIELD JUST AND REASONABLE PRICING

A. The Default Geographic Market of an RTO Footprint Must be Truly Rebuttable

The July 8 Rehearing Order (P 177) recognized that even in an RTO with Commission-approved market monitoring and a single energy market, an RTO-wide geographic market should be rebuttable on a case-specific basis:

> [S]ome parties claim that the Commission should not have allowed participants in ISO/RTO markets to use that region as the default [relevant] geographic market because internal transmission constraints can give rise to relevant geographic areas smaller than a single control area and/or an entire ISO/RTO. We recognize, however, that the ISO/RTO footprint or control area will not always be the appropriate geographic area to consider and have afforded the opportunity for the default relevant geographic market to be rebutted on a case-specific basis.

In practice, however, the presumption appears to be irrebuttable, as is best illustrated by the Commission's decision in *Wisconsin Electric Power Co.*, 110 F.E.R.C. ¶ 61,340, *reh'g denied*, 111 F.E.R.C. ¶ 61,361 (2005). There, substantial evidence, including the Commission's and MISO's treatment of the Wisconsin Upper Michigan System ("WUMS") sub-region as a distinct area ("Narrow Constrained Area" or "NCA") cut off from the rest of MISO by persistent binding transmission constraints, supported a conclusion that WUMS is a separate geographic market for purposes of analyzing market power. Indeed, the Commission conceded that "that transmission constraints do exist that could have an impact on Wisconsin Electric's market power." *WEPCo.*, 111 F.E.R.C. ¶ 61,361 at P 13. Nonetheless, the Commission refused to analyze WEPCo's market power in WUMS separate from the rest of the MISO footprint. If known load pockets such as WUMS (not to mention the Delmarva Peninsula, Southwest Connecticut, or the City of San Francisco, among others) do not rebut the geographic market presumption, or at least make the issue appropriate for investigation, the rebuttable presumption effectively becomes irrebuttable.[58]

In light of the foregoing, the NOPR properly asks whether the Commission should continue "considering the entire geographic region as the default relevant market," and notes that "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." NOPR P 61. The Commission has justified its

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[58] *See also* January 27 Technical Conference, Tr. at 133 (Solomon noting that "the hurdle is fairly steep" for overcoming the presumption).

practice of ignoring such known transmission constraints when assessing market power for MBR purposes on grounds that these RTOs have a single energy market and "sufficient market structure," NOPR P 59, though it is not clear what the Commission means by the latter. In any event, the Commission's practice neglects known facts on the ground and the role that LMP plays in accentuating, rather than mitigating, pricing differences caused by geographic market separation. It is also contrary to conventional antitrust analysis, including as applied by the Commission itself in the merger context. Unless the Commission makes the RTO default geographic market presumption truly rebuttable, it should be abandoned.

RTOs' security constrained economic dispatch and aggregate deliverability standards do not make transmission constraints irrelevant or cause them to magically disappear. Rather, these market designs change the economic consequences of binding transmission constraints. The RTO dispatches higher priced generation (based on suppliers' bids, not on their costs) to prevent violations of transmission limits when transmission constraints are binding. The load located within the transmission-constrained area is then subject to the higher energy prices caused by the dispatch of more expensive generation. The load's access to lower priced generation is limited or blocked entirely. If there is a lack of competition among the generating units that can be dispatched when transmission constraints bind, the owner/operators of those units will exercise market power. The transmission constraint prevents loads from looking to alternative sources of power to defeat an attempt to increase prices by the owner/operator(s) of the unit(s) that must be dispatched inside the load pocket.

For purposes of market power analysis, the Commission must not confuse physical deliverability with economic deliverability. The Commission's section 203 competitive analysis is based upon the Department of Justice/Federal Trade Commission Horizontal Merger Guidelines, which define relevant geographic markets by examining the alternative sources of supply available to load in the face of a price increase.

> Absent price discrimination, the Agency will delineate the geographic market to be a region such that a hypothetical monopolist that was the only present or future producer of the relevant product at locations in that region would profitably impose at least a "small but significant and nontransitory" increase in price, holding constant the terms of sale for all products produced elsewhere. That is, assuming that buyers likely would respond to a price increase on products produced within the tentatively identified region only by shifting to products produced at locations of production outside the region, what would happen? If those locations of production outside the region were, in the aggregate, sufficiently attractive at their existing terms of sale, an attempt to raise price would result in a reduction in sales large enough that the price increase would not prove profitable, and the tentatively identified geographic area would prove to be too narrow.

Horizontal Merger Guidelines § 1.21 (1997).[59] The boundaries of the geographic market are enlarged (or not) based upon whether buyers can *economically* access alternative sellers. Once they cannot, a price increase would be profitable, and the boundaries of the geographic market would be set. *Id.* A transmission constrained area would thus be a relevant market where remote generation could no longer be used to economically serve load in the area.

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[59] "The 'small but significant and nontransitory' increase in price is employed solely as a methodological tool for the analysis of mergers: it is not a tolerance level for price increases." Merger Guidelines § 1.0.

The Commission's Merger Policy Statement similarly describes the relationship between the ability to reach alternative suppliers and the definition of the relevant geographic market:

> Suppliers must be able to reach the market both physically and economically. There are two parts to this analysis. One is determining the economic capability of a supplier to reach a market. This is accomplished by a delivered price test, which accounts for the supplier's relative generation costs and the price of transmission service to the customer, including ancillary services and losses. The second part evaluates the physical capability of a supplier to reach the customer, that is, the amount of electric energy a supplier can deliver to a market based on transmission system capability.

Merger Policy Statement, 61 Fed. Reg. at 68,601; F.E.R.C. Stat. & Regs. at 30,119.[60] In discussing the role of price, the Commission explained:

> [A] supplier that is directly interconnected with a buyer may not be an economic supplier to that buyer if transmission capability across that interconnection is severely constrained or if the transmission charges are greater than the difference between the decremental cost of the buyer and the price at which the supplier is willing to sell.

Id. at 68,599. F.E.R.C. Stat. & Regs. at 30,117. In an LMP market, the transmission charge is represented by the congestion charge, *i.e.*, the difference in the LMPs inside and outside the load pocket. Where transmission constraints cause price separation, one can have separate geographic markets because buyers cannot economically reach alternative, lower-priced sellers. If there is an absence of competition in the load pocket, the sellers in it have the potential to exercise market power.

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[60] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, 61 Fed. Reg. 68,595, 68,601 (Dec. 30, 1996), *reprinted in* [1996–2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,044, at 30,121 (1996).

While an FTR might provide a hedge against the increased prices in the load pocket, the ability of the FTR to protect the consumer is limited by its availability, which is often reduced in load pockets due to transmission constraints. In other words, transmission customers serving loads in locations where FTRs are needed the most often have the hardest time obtaining them.[61] In addition, FTR values are set in the Day-Ahead market, so if the market power exercise occurs in the Real-Time market, the consumer will not be fully hedged. In SPP, which is about to adopt a system of locational pricing for imbalance energy, there are no FTRs, despite the fact that customers could face extremely high prices on a locational basis.

Nor should the Commission ignore that even in RTO markets, some LSEs may be required to demonstrate physical deliverability of remote resources to their loads. For example, while MISO applies an aggregate deliverability standard for purposes of network resource designation, MISO loads in areas subject to Midcontinent Area Power Pool ("MAPP") reliability rules must show the ability to physically deliver reserve capacity to a specific load. The Commission's default, RTO-wide geographic market, which is premised on aggregate deliverability, is inconsistent with these market rules. Thus, the competitive conditions in a load pocket are relevant to determining the risk of market power exercise. For example, if some or all of an MBR applicant's control area (in MISO or SPP) or transmission service territory (in PJM, California or the Northeast RTOs) is separated from other parts of the RTO, as reflected in differences in LMPs, the areas so separated could be distinct geographic markets for purpose of competitive

[61] Loads will not be protected against congestion risks to the extent FTRs are insufficient, which is likely to be the case where transmission is constrained because FTRs are allocated only where they are simultaneously feasible.

analysis. Where transmission constraints exist, a geographic market based upon the entire RTO footprint overlooks such adverse competitive effects and thus would be inconsistent with accepted antitrust analysis, as well as Commission policy and precedent.

In the section 203 context, the Commission has correctly found the transmission constraints lead to distinct geographic markets, at least when those constraints are binding. For example, in *Wisvest-Connecticut, LLC*, the Commission rejected arguments that the entire ISO-NE footprint should serve as the relevant geographic market, citing the role of transmission constraints in creating smaller geographic markets. *Wisvest-Connecticut, LLC*, 96 F.E.R.C. ¶ 61,101, at 61,401 (2001). In *Duke/Cinergy*, Dr. William Hieronymus identified as one of the relevant geographic markets for his Appendix A analysis the "MISO Submarket," which included all of MISO but excluded the Louisville Gas & Electric control area, the Wisconsin-Upper Michigan System, Iowa, and Minnesota.[62] *Duke Energy Corp. & Cinergy Corp.*, 113 F.E.R.C. ¶ 61,297, P 24 & n.5 (2005). The Commission accepted Dr. Hieronymus's analysis. *Duke/Cinergy*, 113 F.E.R.C. ¶ 61,297 at P 70. Similarly, in *Exelon Corp. & Public Service Enterprise Corp., Inc.*, the Commission adopted and analyzed several sub-markets within the PJM RTO footprint, namely, PJM East and Northern PSEG. 112 F.E.R.C. ¶ 61,011, at PP 12, 17, 122. With respect to the latter, the Commission said:

> We are not convinced by Applicants' argument that Northern New Jersey is not a relevant geographic market. As noted by the PHI Companies and others, there are times

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[62] Exhibit J-1 at 31-32, Application, Docket No. EC05-103-000 (filed July 12, 2005) (elibrary Accession No. 20050715-0126).

> when transmission constraints bind, leaving Northern New Jersey isolated from the rest of PJM-East.

Id. P 122. No reasonable basis exists to distinguish between the competitive analyses used to establish relevant geographic markets in the section 203 and the section 205 contexts.

APPA and TAPS therefore can support continued used of the RTO footprint as the default geographic market only if that presumption is truly rebuttable and applicants are required to support whether the geographic market should be the entire footprint or a smaller region with specific facts. As recommended above, in advance of each region's MBR review RTOs should provide market participants with transmission studies that reveal where binding transmission constraints arise so that those data can be used in addressing the proper relevant geographic market. Only with such a fact-based definition of the relevant geographic market will the Commission be able to fulfill its responsibilities under the FPA and APA to ensure that MBR determinations are based upon "empirical proof" and "substantial evidence."[63]

B. RTO Mitigation Measures Should Not Be Assumed Sufficient to Address Seller Market Power

The MBR NOPR appropriately asks whether, "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?" NOPR P 62. The answer is "yes."

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[63] *Farmers Union*, 734 F.2d at 1499, 1510; 5 U.S.C. § 706(2)(E).

In the MBR authorization context, the Commission requires mitigation when the seller is found to have (or accepts the presumption of) market power. Cost-based default mitigation is intended to address that market power. In contrast, while the Commission has approved as just and reasonable RTO market monitoring and mitigation plans, those plans are designed to address market power risks generally that may arise in the operation of RTO-operated markets. They are not focused on the specific market power concerns presented by a particular seller found to have market power. Indeed, the Commission itself has said that RTO mitigation and the Market Based Rate assessment are different and that "pieces of one should not automatically be used as precedent for the other."[64]

A comparison between the Commission's default cost-based mitigation and RTO mitigation measures shows the differences between the two and the inappropriateness of assuming that RTO mitigation suffices to mitigate market power found via specific seller assessments under the MBR Standards. RTO mitigation measures apply only to spot markets – Day-Ahead and/or Real-Time – and do not apply to weekly, monthly or long-term transactions, including those negotiated on a bilateral basis.[65] Thus, the scope of RTO mitigation is significantly narrower than the default, cost-based mitigation the Commission prescribes. In terms of spot market mitigation itself, RTO mitigation is far less protective than the Commission's cost-based default of incremental cost plus 10% and is so generous to sellers that they must follow extremely aggressive bidding strategies to be at risk of having their bids mitigated. For example, in MISO before

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[64] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,157, P 242 (2004).

[65] In the April 14 Order (at P 154), the Commission correctly abandoned the assumption that spot market mitigation suffices to mitigate market power in longer term product markets.

market mitigation would kick in under the so-called "conduct and impact" test, a seller could increase its bids by the lesser of 300% or $100 per MWh over its prior bids and cause prices to rise by more than the lesser of 200% or $100 per MWh.[66] In SPP, mitigation measures would permit price increases from over 100% to nearly 3000% over the level that would normally be found in a competitive market, and the bid caps are set without any reference to the actual costs of the seller with market power.[67] In both instances, the mitigation measures would allow sellers to charge rates far above incremental cost plus 10%.

The Commission may respond that the kinds of thresholds or bid caps called for under RTO mitigation schemes are necessary so that RTO mitigation measures do not "over-mitigate" and interfere with the operation of competitive markets. However, that is exactly the reason why the Commission should not assume that RTO mitigation measures suffice in the case of a particular supplier found to possess market power. The hope is that RTO markets will generally operate in a competitive manner with the mitigation measures applying when market power risks are elevated. By contrast, the mitigation required when a seller fails the Screens/DPT arises because the seller has already been found to have market power. It is not a fleeting phenomenon. Under such circumstances, the Commission cannot assume that competitive forces or limited RTO mitigation measures will keep prices in check so that they are just and reasonable.[68]

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[66] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163, P 308 (2004).

[67] *Southwest Power Pool, Inc.*, 114 F.E.R.C. ¶ 61,289, PP 153-75 (2006).

[68] This is equally true in transmission constrained areas – in both MISO and SPP the mitigation measures apply when there are increased risks for successful market power exercise.

There is no reason why the Commission in cases involving a seller in an RTO market that fails the Screens/DPT could not cap the seller's bids in the RTO's Day-Ahead and Real-Time markets to its own marginal cost (including legitimate and verifiable opportunity costs) plus 10%, while allowing the seller to receive the clearing price, regardless of whether the price is set by its bid or not. Such an approach to mitigation applies in PJM where sellers retain their MBR authority, receive the clearing price, but have their bids capped when constraints bind. The Commission has found that such an approach is generally not unjust and unreasonable. *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,112, P 36-37 (2004). Where sellers wish to no longer be limited to cost-based bids, they can undertake structural mitigation, such as constructing transmission that would relieve the constraint, and seek removal of the bid caps once the new facilities were built and the constraint relieved.

VIII. THE COMMISSION SHOULD MAKE MODIFICATIONS TO LIMITED ASPECTS OF THE MBR STANDARDS TO IMPROVE THEIR ABILITY TO ASSESS MARKET POWER

A. The Pivotal Supplier Screen Should Be Conducted For Monthly, Not Just Annual, Peaks

The NOPR proposes "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." NOPR P 42. Examining only the one extreme annual peak case ignores the fact that a supplier could be pivotal at other times. This fact is illustrated by the MISO market monitor's recent State of the Market Report, which found the presence of pivotal suppliers in many hours of the year, not just at the annual peak (or annual peak months).[69] In the affidavit accompanying APPA/TAPS's February 4, 2004 SMA Comments (hereafter "Kirsch SMA Affidavit),[70] economist Dr. Laurence Kirsch explained (at 8-9):

> Screens should recognize that the ability to exercise market power changes over time with changes in load levels, generation output, and the availability of generation and transmission facilities. At a minimum, screens should examine market power for the on-peak and off-peak periods of the different seasons and, as appropriate, for forthcoming years.

The Commission Staff has previously proposed to conduct the pivotal supplier analysis on a monthly basis to better capture changes in the applicant's market power.[71] The current Pivotal Supplier Screen measures the extreme situation in which a suppler can single-handedly reduce operating reserve margins to levels that trigger emergency procedures or even require load shedding. As Dr. Kirsch has pointed out: "This ability to cause system distress is certainly sufficient to establish the ability to exercise market power; but there are many other situations in which a supplier can exercise market power

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[69] Pages 140 and 142 of the June 2006 Presentation of MISO's Independent Market Monitor regarding the State of The Market reported that a large number of areas affected by binding transmission constraints (and thus producing geographic markets separate from other parts of MISO because of the inability of load to look outside of the immediate area for supply alternatives) have pivotal suppliers in many hours of the year. The Presentation is available at http://www.midwestiso.org/publish/Document/7be606_10b7aacd66e_-7d540a48324a/2005%20State%20of%20the%20Market%20Report.pdf?action=download&_property=Attachment (last viewed Aug. 2, 2006).

[70] February 4, 2004 "Post-Technical Conference Comments of the American Public Power Association and the Transmission Access Policy Study Group," filed in Docket No. PL02-8-000, *Conference on Supply Margin Assessment* ("February 4, 2004 SMD Comments"), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10057963 (last visited Aug. 2, 2006). APPA and TAPS filed Dr. Kirsch's Affidavit in RM04-7-000 on June 30, 2004.

[71] *Conference on Supply Margin Assessment*, Notice of Technical Conference, Staff Paper at 6-7 (December 19, 2003) *available at* http://www.ferc.gov/EventCalendar/Files/20040112104841-PL02-8-000-notice.pdf (last viewed Aug. 2, 2006). Given the data that applicants must already gather, running the Pivotal Supplier Screen for each month represents an insignificant amount of additional work.

without having such an ability." Kirsch SMA Affidavit at 9. *See also* January 27 Technical Conference, Tr. at 11 (Bushnell).

A monthly analysis is particularly important to gauge the effect of outages. Both the seller's and its competitors' planned outages could have dramatic effects on the pivotal supplier result. More generation should be on-line during peak seasons, and the larger amount of supply available to the market presents competitive conditions different from the supply situation when major generation units or transmission lines are on scheduled outage.[72]

A monthly Pivotal Supplier Screen is also needed to help ensure that suppliers with market power, but that pass the Market Share Screen because they have less than 20 percent market share in any season, are accurately assessed. In the April 14 Order (P 104), the Commission observed that: "While a supplier with less than a 20 percent market share, in certain circumstances, can affect the market price during periods of limited supply alternatives, our pivotal supplier analysis addresses such situations by examining whether there are sufficient competing supply alternatives to meet the market's peak load." However, the Pivotal Supplier Screen will only do this if the supplier happens to be pivotal during the peak month.

Thus, it is plainly insufficient under the FPA for the Commission to needlessly narrow its Pivotal Supplier Screen to just the single peak month, ignoring the potential for exercise of market power in other months. Monthly application of the Pivotal Supplier Screen is required.

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[72] The April 14 Order (P 97) does not require that the annual peak-based Pivotal Suppler Screen reflect planned outages. If conducted on a monthly basis, the Pivotal Supplier Screen should reflect planned outages.

B. The Native Load Proxy for the Market Share Screen Should At Least Remain Unchanged, If Not Adjusted Downward

The NOPR proposes to increase the size of the native load proxy used for the Market Share Screen from the minimum native load peak demand for the season to the average native load peak demand for the season. NOPR P 44. The Commission states that the purpose of the adjustment is "[t]o reduce the number of 'false positives' in the wholesale market share screen." *Id.* Notably, the Commission does not identify the cases where it believes the Market Share Screen has produced "false positives." Rather, the proposal appears to be a results-driven effort to eliminate the need for some public utilities to avoid having to submit a DPT.

For example, in *Acadia Power Partners LLC*, 111 F.E.R.C. ¶ 61,239 (2005), and *Kansas City Power & Light Co.*, 111 F.E.R.C. ¶ 61,395 (2005), the applying utilities failed the Market Share Screen, but passed the Pivotal Supplier Screen. In both cases, they opted to submit the DPT, and after consideration of their DPTs, the Commission concluded to allow the utilities to retain their MBR authority. *Acadia Power Partners, LLC*, 113 F.E.R.C. ¶ 61,073 (2005); *Kansas City Power & Light Co.*, 113 F.E.R.C. ¶ 61,074 (2005). While APPA and TAPS are not in a position to determine whether the NOPR's proposed upward adjustment in the native load proxy would have permitted either utility to pass the Market Share Screen, the fact that the utilities submitted the DPT and the Commission ultimately allowed them to retain their MBR authority does not mean that the initial screen results produced a "false positive." In both cases, the DPT results were mixed with some failures of the DPT's screens. *See Acadia*, 113 F.E.R.C. ¶ 61,073 at P 36 and *Kansas City*, 113 F.E.R.C. ¶ 61,074 at P 26. As a result, the Commission exercised its judgment and concluded that the utilities should retain MBR authority. These are not examples of false positives, but instead show the Commission doing its job – examining the specific facts of a case and making a decision rather than applying its MBR tests mechanistically.

The Commission's "false positives" justification loses sight of the stakes involved in the MBR determination. The price of a false positive associated with the initial Screens will be the applicant's submission of the DPT. That price pales in comparison to the supra-competitive prices and market power exercise that can result from a false negative. It is thus entirely appropriate for the Commission to take a closer look when a utility fails the initial screens, even when the Commission ultimately allows MBR authority. Meaningful review upfront helps to nip potential market power problems in the bud.

Beside lacking evidentiary basis, the proposed adjustment is unprincipled. When the Commission originally adopted the native load proxy for the Market Share Screen, it said the screen should reflect "all of the capacity that is available to compete in wholesale markets at some point during the season." April 14 Order at P 92. It stated:

> By subtracting the generation needed to serve native load on the minimum load day of the season, we identify *all* of the capacity that is available to compete in wholesale markets at some point during the season. In other words, the use of this proxy for native load reflects the fact that the rest of the applicant's generation was uncommitted and available at some point during that season to sell in wholesale markets. For the purpose of constructing a reasonably balanced conservative screen, we will consider all such available capacity for both applicants and competing suppliers.

Id. P 92 (emphasis added); *see also id*. P 89 (quoting *Louisville Gas & Elec. Co.*, 62 F.E.R.C. ¶ 61,016, at 61,146 (1993)). However, the April 14 Order's proxy fails to satisfy the Commission's stated purpose. Instead of capturing all the capacity available, it identifies only *some* of the capacity available to compete in wholesale markets during the season (the difference between the needle peak and the minimum peak, while ignoring the capacity measured by the difference between the minimum peak and the minimum load.) Now the Commission proposes to eliminate even more of the capacity that is available to compete at some point in the season, by increasing the proxy to the average native load peak demand for the season. The proposed adjustment merely compounds the flaws in its original native load proxy.

Further, adoption of the Commission's proposal would mean that the MBR screens would make no assessment of off-peak periods. As Dr. Kirsch has explained, "screens should examine market power for the on-peak and off-peak periods of the different seasons." Kirsch SMA Affidavit at 8-9. Indeed, the Commission intends the Market Share Screen to measure market power during off-peak times. April 14 Order at P 72. The proposed upward adjustment thus fails to assess generation market power during important periods when customers could in fact be harmed by its exercise.

The NOPR states that its proposed change makes "the market share screen consistent with the deduction allowed under the pivotal supplier screen." NOPR P 44. However, consistency across the two screens defeats the purpose of having more than one screen. The Market Share Screen is intended to reflect capacity that could compete, including during off-peak periods. By contrast, the Pivotal Supplier Screen is specifically intended to measure market power risks at system peak.

If the Commission nonetheless believes some consistency is desired, it can achieve it by using a native load proxy for the market share screen based upon the average minimum loads. Such a proxy would better achieve the Commission's original intent of a screen that identifies "all of the capacity that is available to compete in wholesale markets at some point during the season." April 14 Order at P 92. Indeed, for the reasons described above, the Commission would be justified in modifying the proxy to reflect average minimum loads.

In sum, the native load proxy should remain unchanged, or adjusted downward to reflect average minimum loads.

C. The Market Share Screen Should Include a Set of Results Based Upon Firm Transfer Capability to Better Reflect Competitive Conditions for Long-Term Products

In the April 14 Order (PP 154-55), the Commission recognized the need to consider and provide mitigation for market power in long-term markets. Its decision was based, at least in part, on testimony/affidavits from APPA and TAPS witnesses demonstrating that LSEs have obligations to secure power supply on a long-term basis and cannot look to spot markets to satisfy these needs. *Id.* They further demonstrated, and the Commission agreed, that a small LSE may not be in a position to build a generation unit on its own.[73] *Id.* In light of these findings, the Commission must examine risks for market power exercise for long-term products as part of the MBR test.

Sales of long-term products require that sellers have the capability to sell that product. For example, a small transmission dependent LSE looking to purchase all of its power supply needs in the market, *e.g.*, round-the-clock capacity and energy with an ability to follow load, will generally not be able to look to an IPP with a single peaking

[73] In fact, in some states LSEs may be barred or discouraged from building their own plants to serve their retail customers, for example, due to restructuring legislation.

plant for supply. Its only choice may be a public utility with a fleet of plants that provides similar services to itself for sales to retail customers. Such sales also require firm transmission service. A smaller municipal system with little or no generation of its own cannot rely on non-firm transmission service for its purchases of full-requirements supply. Likewise, some capacity products, especially those needed to fulfill installed reserve requirements, may satisfy regional reliability rules only if deliverable to load via firm transmission service. It may well be that the geographic market for such products will be smaller than for energy products deliverable on a non-firm basis.[74] The Commission should not assume that the geographic market for each kind of product is the same.

The Pivotal Supplier Screen is not well adapted to examining market conditions for long-term products, such as those described above. It basically examines what suppliers can sell energy during a peak hour, including interruptible energy sales to the extent non-firm service is available. According to the Commission:

> [The pivotal supplier screen] essentially asks whether the market demand can be met absent the applicant during peak times. Thus, the pivotal supplier screen measures market power at peak times, and particularly in spot markets.

April 14 Order at P 72. While the Commission should be examining competition in short-term energy markets, the competitive landscape represented by the Pivotal Supplier screen results may have little bearing on what suppliers could sell LSEs long-term, firm power supplies.

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[74] For example, CBM can be used on a non-firm, but not on a firm, basis.

The Market Share Screen should be performed to provide better insight into the market for long-term products. The Screen provides a structural perspective on the market – what sellers have capacity to sell and how a particular seller compares to its competitors. According to the Commission:

> The uncommitted market share analysis indicates whether a supplier has a dominant position in the market, which is another indication of whether the supplier has unilateral market power and may indicate the presence of the ability to facilitate coordinated interaction with other sellers. The market share screen is also useful in measuring market power because it measures an applicant's size relative to others in the market.

Id. Presently, the Market Share Screen uses an SIL study that includes non-firm transmission capacity. To understand what capacity may be available and backed by firm transmission service, the Market Share Screen should also be run using an SIL study of firm transmission capacity only, preferably using ATC for the upcoming annual period, but at minimum run without CBM modeled as available, even on a non-firm basis. By running the Market Share Screen with both firm and non-firm transmission capacity, the Commission would have a more complete picture of competition in the market for longer term products.

The need to examine screen results based upon firm availability is illustrated by testimony regarding the difficulties LSEs have had obtaining firm transmission service to import firm power supply, including on a long-term basis. For example, on behalf of TAPS and MMTG, Anne Kimber testified at the December 7, 2004 Technical Conference to the inability of loads of less than a megawatt to secure firm transmission paths into the MidAmerican Energy system in Iowa.[75] Terry Huval, appearing on behalf of TAPS and Lafayette Utilities System at the January 28, 2005 Technical Conference, described Lafayette's difficulty bringing power into the Entergy system from CLECO, despite Lafayette's having a firm path.[76]

The Commission already requires analysis of ATC for the Appendix A merger analysis. In the MBR context, it must also base its analysis on what market participants themselves rely upon when seeking to transact in the market. OASIS sites post ATC for both firm and non-firm transmission transactions. While ATC measures are not perfect, they reflect the transmission capacity market participants are told is available when they determine the feasibility of a transaction. The requirement that Commission MBR decisions be based on empirical proof means that the Commission must take markets as it finds them. If the Commission looks at markets as they operate today particularly in non-RTO regions, it will find ATC as the measure of transmission capability for firm transmission service. Thus, the Commission should require sellers to calculate the simultaneous available import capability of their systems using the firm ATC values that transmission customers are given, and use those results to prepare one of the iterations of the Market Share Screen.[77]

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[75] Written Statement of Anne Kimber on behalf of MMTG and TAPS for the December 7 Technical Conference, Docket No. RM04-7-000 (filed December 7, 2004), *available* at http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10328815 (last viewed Aug. 2, 2006).

[76] Written Statement of Terry Huval on Behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, prepared for the January 28, 2005 Technical Conference, Docket No. RM04-7-000, at 5, (filed Jan. 31, 2005), *available at* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10391023 (last viewed Aug. 2, 2006).

[77] Consideration could be given to adjusting firm ATC figures where it can be shown that a reserved path represents a genuine source of competing supply into the relevant geographic market. However, if the path is committed to a long-term power sale, an adjustment would be inappropriate.

Failure of the "firm" Market Share Screen could guide the subsequent investigation of a seller's market power, if the seller otherwise did not accept the presumption of market power and go straight to mitigation. That investigation could focus on identification of the potential sellers of long-term, firm products, such as load-following service. Such products are often traded in bilateral markets. Issues the Commission could examine would include which suppliers have historically sold such products, which suppliers have the capability to sell such products, the import capability of the transmission system for such products, and entry conditions for new sellers of the products. As described in Part I above, the Commission must also examine relevant historical and forward-looking evidence to make an informed judgment about a seller's market power.

Finally, by requiring that the Market Share Screen include a run where CBM set asides can adversely affect the screen results for the seller, the Commission will have created incentives for transmission providers seeking MBR authority to discipline their CMB nominations. Larger CBM sets asides would translate into less import capability, which would increase the dominance of the seller and lower its chances of passing the MBR standards. It is entirely appropriate that CBM set asides have a practical impact on the seller's own sales, since they have such a substantial impact on the power supply arrangements of transmission customers.

D. Questions of Control Are Fact-Specific and Should Be Based Upon Contract Language

APPA and TAPS largely agree with the NOPR's discussion regarding control over generation and whether capacity associated with particular contracts should be added or subtracted for purposes of determining "uncommitted capacity." NOPR PP 46-49.[78] The NOPR states the following general principle:

> The Commission has stated that contracts can confer the same rights of control of generation or transmission facilities as ownership of those facilities. 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 performing the generation market power screens. The capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility.

NOPR P 47 (footnotes omitted). While APPA and TAPS agree with the principle, the fact-specific nature of the control inquiry, which the NOPR recognizes (at P 49), means that generic findings or presumptions may or may not be helpful. They would helpful if the particulars of a contract aligned with the factual assumptions underlying a presumption. If the assumptions and facts were different, a presumption could produce the wrong result. Accordingly, as part of the applicant's assigning control over long-term contracts for purposes of the Screens/DPT, the Commission should require an applicant to submit the relevant contracts with the MBR application or triennial update and identify the contractual provisions that support the applicant's control determinations.[79] In this way, the Commission and intervenors can test the applicant' control assumptions.

In examining the applicant's claim and the associated contracts, the control factors the Commission identifies, such as plant management, provide an appropriate

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[78] APPA and TAPS also support the NOPR's clarification that native load shall be defined consistent with section 33.3(d)(4)(i) of the Commission's regulations, 18 C.F.R. § 33.3(d)(4)(i). NOPR P 45.

[79] Confidentiality concerns can be addressed with appropriate protective orders.

starting point. However, the Commission should not limit its inquiry to plant management. Other kinds of contracts, such as marketing arrangements, could also provide a seller with the ability to determine whether capacity reaches the relevant market. For example, under some contracts the owner/operator of a plant turns over marketing to a third party, though retaining, at least on paper, the ability to market the output of capacity not sold by the marketer. Such a contract's provisions could provide the owner/operator with an increasing stake in the profits associated with the third party's marketing of the output such that successful efforts by the marketer to withhold the output (whether physically or economically) to increase price would not prompt the owner/operator to sell the output in competition with the marketer. In other words, the contract's terms could neutralize the owner/operator's incentive to compete against the marketer. In such a case, the control of the output ought to be assigned to the marketer, even though actual operational control of the plant remains with the plant owner.

E. The Concentration Threshold for the DPT Should Be 1800 HHI

The NOPR proposes to retain the concentration threshold of 2500 HHI for the DPT applied in the MBR context. NOPR P 43. The Commission's original adoption of the 2500 HHI standard was and remains an unsupported, unjustifiable departure from its prior reliance on HHIs, including under the Merger Policy Statement, and is contrary to accepted antitrust economics. The Commission should instead establish 1800 as the threshold. If the Commission retains a 2500 threshold, then consistency demands that it be used with the 15% market share standard the DoJ advocated in the oil pipeline industry comments from which the 2500 HHI was lifted.[80]

There is no basis for using in the electric utility industry an HHI threshold proposed in the context of the oil pipeline industry. Electricity generation markets present far different economic characteristics.[81] For example, oil pipeline transportation can be substituted with truck or ship transportation. Oil can be stored. Substitutability and storability, characteristics that do not appear in electric generation markets, both provide means for market participants to defeat an attempted price increase, which would make use of the higher 2500 HHI less risky for consumers.

The Commission should adhere to the "Unconcentrated < 1000 < Moderately Concentrated < 1800 < Highly Concentrated" schema set forth in its Merger Policy, which is based upon the Horizontal Merger Guidelines. With respect to the Merger Guidelines' 1800 threshold, "there has been fairly little quibbling about the precise thresholds that the government has selected for creating presumptions about legality." IV Phillip E. Areeda *et al.*, *Antitrust Law* ¶ 932a, at 154 (rev. ed. 1998).[82] In specific

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[80] *See* Comments of the United States Department of Justice in response to Notice of Inquiry Regarding Market-Based Ratemaking for Oil Pipelines, Docket No. RM94-1-000 (Jan. 18, 1994) ("DOJ Comments"); U.S. Department of Justice, Oil Pipeline Deregulation: Report of the U.S. Department of Justice (May 1986) ("Oil Pipeline Report").

[81] *See also* Part II.A. above.

[82] Even an 1800 HHI may be higher than appropriate. *See, e.g.*, Thomas E. Kauper, *The 1982 Horizontal Merger Guidelines: Of Collusion, Efficiency, and Failure, in* Antitrust Policy in Transition: The Convergence of Law and Economics 171, 189 (Eleanor M. Fox & James T. Halverson eds., 1984) ("This [1800] level … is both higher than economic analysis dictates, and too great a departure from judicially developed standards.").

circumstances where justified by facts, applicants or intervenors can seek to demonstrate that HHIs above or below 1800 do not or do raise market power concerns.[83]

In addition to the foregoing principles and precedents supporting an 1800 HHI threshold, the Commission's obligation to protect consumers from market power requires that the threshold be lowered from 2500 HHI. As describe in Part II.A. above, electricity markets have characteristics that make them more susceptible to coordinated interaction, *i.e.*, collusion, than other markets. The antitrust agencies and antitrust economists established the 1800 HHI threshold based upon collusion risks for industry generally. V Phillip E. Areeda *et al.*, *Antitrust Law* ¶ 931a3, at 159-163 (rev. ed. 2003). It would be a mistake to weaken that threshold for an industry where collusion risks are higher than for other markets. The 2500 HHI threshold is such a mistake.

However, if the Commission does retain the 2500 standard, it should at least be consistent with the DoJ Comments from which it was taken, which advocated a 15% — as opposed to the proposed 20% — market share as the standard for presumption of no significant market power. *See* DOJ Comments at 13. Nothing in the DoJ Comments suggests that the Commission should get to play pick and choose, especially to the detriment of the customers it is supposed to protect. From a consumer protection standpoint, if a more generous HHI level is selected, it must be married to a less generous market share threshold.

[83] *Cf.* Horizontal Merger Guidelines, § 1.5 (noting that thresholds provide a framework, not precise lines of demarcation).

IX. NON-DISCRIMINATORY TRANSMISSION REMAINS A CRITICAL COMPONENT OF MBR AUTHORIZATIONS

A. It Is Too Early to Say Whether an OATT Mitigates Transmission Market Power

The NOPR notes the pendency of the Commission's NOPR in Docket No. RM05-25-000 on revisions to the OATT and proposes "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." NOPR P 90. It also acknowledges suggestions that a transmission planning and expansion obligation can ameliorate vertical market power and asks whether the "planning and expansion efforts under the OATT Reform Rulemaking will address commenters' concerns here." NOPR P 94. APPA's and TAPS' response is "we'll have to wait and see." The current OATT is clearly not adequate, as the Commission has found. APPA and TAPS each is submitting comments contemporaneously with these MBR comments in which they address issues in the OATT Reform Rulemaking, including the critical issue of transmission planning and expansion. Whether the OATT as revised will address APPA's and TAPS's concerns about the interaction between transmission market power and generation market power will depend upon the outcome of the OATT proceeding. In any event, the Commission must ensure that its decisions in the MBR NOPR reflect the results of the OATT Reform Rulemaking. Further, the Commission must recognize that improvements in transmission planning and expansion, even if successfully implemented, will not bear fruit immediately. Thus, there will be a continuing need to address transmission market power issues, even after adoption of a revised OATT.

B. Revocation of MBR Authority Should Be Considered in Appropriate Cases for Material Violations of the OATT

The Commission correctly states in the NOPR that:

> [T]he 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.

NOPR P 91. It continues that "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." *Id.* Because the "nexus" standard is not appropriate, APPA and TAPS propose instead that the Commission consider MBR revocation for "material violations" of a transmission provider's OATT that deny customers the just, reasonable, non-discriminatory and comparable transmission service that is essential to mitigating transmission market power.

Restricting MBR revocation to cases where specific OATT violations have a nexus to MBR authority will leave that authority in place where it is plainly inappropriate. A filed OATT is a prerequisite to MBR authority. A serious violation of the OATT diminishes or even nullifies the transmission market power mitigating effect of the filing requirement. If the violation is material, that is, if the violation effectively denies, delays, or diminishes the availability of transmission service or raises its costs, that alone should suffice for consideration of revocation of MBR authority.[84] Whether the violation had a "nexus" to the seller's MBR sales may well be irrelevant.

The "nexus" standard adds an unnecessary and counter-productive test. Take the case of a transmission provider that fails to engage in proper planning and construction of the transmission system. Such failure may have no express link with the provider or an affiliates' MBR sales, but rather may have the effect of weakening the competitive position of wholesale customers that are captive to the transmission provider's system, leaving them more vulnerable to buyout. A nexus requirement could divert the Commission and injured parties through needless disputes about whether the alleged violator used the OATT violation to enable a specific sale under its MBR tariff authority, ignoring the larger picture painted by the transmission provider's anticompetitive conduct and exercise of transmission market power.

Thus, instead of the "nexus" standard, the Commission should require that the OATT violation be "material," *i.e.*, that the violation denies customers the just, reasonable and non-discriminatory and comparable transmission service that is essential to mitigating transmission market power.

X. THE NOPR VIEWS ENTRY BARRIERS TOO NARROWLY

A. Regardless of Origin, Entry Barriers Should Be Considered in Both the Vertical and Horizontal Market Power Analyses

The NOPR discusses entry in relation to possible barriers to entry that the MBR applicant can erect. NOPR P 92. While such entry barriers are appropriately considered as part of the vertical market power test, entry barriers are relevant regardless of their

[84] While an OATT violation, such as failure to return a deposit, could be serious, it would not merit revocation of MBR authority if it did not result in the denial of non-discriminatory service.

origin. Take for example the cases of siting restrictions in the state of Florida. The Commission Staff characterized the law, and a related Florida Supreme Court decision,[85] as a "situation significantly imped[ing] … development of competitive energy markets in peninsular Florida."[86] The Commission Staff further explained:[87]

> Florida law restricts construction of merchant plants. Regardless of the purpose of the state statutes construed by the state court, granting licenses only to an applicant who has demonstrated that a utility serving retail customers has a specific need for all the power to be generated at the proposed plant severely limits the market mechanisms by which power may be delivered to loads. In so limiting the generation and delivery of power, it creates inefficiency by replacing market allocation with administrative determinations. The Florida decision creates a significant barrier to entry … .

Such barriers affect entry regardless of how they arise.

Further, by focusing as part of the vertically market power test only on entry barriers that the seller can erect, the Commission overlooks the impact that entry barriers have on horizontal generation market power. Standard antitrust analysis considers whether entry barriers, regardless of their origin, affect the durability of seller market power. Horizontal Merger Guidelines, § 3; V Phillip E. Areeda *et al.*, *Antitrust Law* ¶ 1125f, at 72-76 (rev. ed. 2003). Likewise, the Commission's Merger Policy Statement provides for the consideration of entry conditions. Merger Policy Statement, 61 Fed. Reg. at 68,616. Entry that is timely, likely and sufficient may mitigate seller market power, whereas the absence of entry can reinforce it. Consideration of entry barriers (or

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[85] *Tampa Electric Co. v. Garcia,* 767 So.2d 428 (Fla. 2000).

[86] "Investigation of Bulk Power Markets – Southeast Region," Staff Report on U.S. Bulk Power Markets, pt. 2, Docket No. EL00-95-000, at 3-2 (Nov. 1, 2000) (elibrary Accession No. 20001108-072).

[87] *Id.* at 3-41.

conditions) would be particularly relevant to long-term product markets. For example, a shortage of suitable plant sites, absence of necessary infrastructure (either transmission or gas pipeline), financing difficulties, or long siting processes could enhance a seller's market power, and certainly make unsupportable an assumption that long-term generation markets are inherently competitive.[88] While APPA and TAPS do not propose a distinct analytical step for consideration of entry barriers as part of the MBR test, the Commission must be receptive to claims that entry barriers in the seller's market provide or enhance market power, even if the seller itself did not erect the barriers.

B. The Commission Should Not Codify the Entry Barriers Considered, Nor Exclude Interstate Natural Gas Transportation

The NOPR "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." It specifically cites "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." NOPR P 93. While illustrations of entry barriers can provide guidance to applicants and market participants, the Commission should not limit the kinds of entry barriers it will consider.[89] Electricity markets are dynamic and inputs that may not have created

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[88] Order No. 888, 61 Fed Reg. 21540, 21,553 (May 10, 1996), *reprinted in* [1991-1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, at 31,656-57 (1996).

[89] And, as just described, should not focus solely on entry barriers erected by the seller itself.

concerns previously could become worrisome in the future. An example is coal transportation by rail, which has lately become even more critical than in the past.

APPA and TAPS do not oppose the Commission's clarification "that applicants need not address interstate transportation of natural gas suppliers because such transportation is regulated by this Commission." NOPR P 93. However, the absence of a requirement for applicants to affirmatively address interstate natural gas transportation should not preclude intervenors from raising concerns and introducing evidence regarding a seller's position in the interstate natural gas capacity market. To do otherwise would assume perfection in the Commission's regulation of interstate gas transportation, or that market participants would never find a way to develop a dominant position in natural gas transport. Neither assumption is justified. Thus, the Commission should clarify that it will consider control over interstate natural gas transportation if the issue is raised in an MBR proceeding.

C. The Entry Barriers Affirmation Should Be Verified By a Senior Corporate Official

The NOPR proposes "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." NOPR P 92. The Commission should require such statement to be verified by a duly authorized corporate official, similar to verifications required in the section 203 context. *See* 18 C.F.R. §§ 33.1(c)(5), 33.2(j).

XI. THE NOPR'S AFFILIATE ABUSE PROPOSALS ARE ON THE RIGHT TRACK

APPA and TAPS support the NOPR's proposed codification of prohibitions related to power sales between affiliates and the commensurate statement that violations of the affiliate abuse conditions will constitute MBR tariff violations. NOPR P 109. The ability of the Commission to apply its considerable remedial power, including in appropriate cases the anti-market manipulation rules, for violations of the affiliate abuse conditions should significantly aid enforcement, to the ultimate benefit of customers. A consistent code of conduct across all sellers will create greater transparency, which also aids enforcement. APPA and TAPS provide the following comments on some of the Commission's specific affiliate abuse proposals.

The Commission seeks comment on whether the definition of captive customer adopted in the Final Rule on transactions subject to section 203 should apply in the MBR context. NOPR P 110. It states that in the section 203 Final Rule, it defined "'captive customer' to mean 'any wholesale or retail electric energy customers served under cost-based regulation.'"[90] In the rehearing order on the section 203 Final Rule, responding to concerns raised by APPA and the National Rural Electric Cooperative Association, the Commission also clarified and added language to impose reporting obligations for "public utilities that own or provide transmission service over Commission-jurisdictional transmission facilities" similar to the obligations it had imposed on utilities with captive customers.[91] The Commission should take similar action here. Affiliate abuse not only raises costs to wholesale customers, it also can also harm competition (*e.g.*, via cross-subsidization that provides the seller with an unfair

[90] NOPR P 110 (citing *Transactions Subject to FPA Section 203*, Order No. 669-A, 71 Fed. Reg. 28,422 (May 16, 2006), *reprinted* in F.E.R.C. Stat. & Regs. ¶ 31,097 (2006)).

[91] *Transactions Subject to FPA Section 203*, Order No. 669-A, 71 Fed. Reg. 28,422, 28,440-41 (May 16, 2006), *reprinted in* F.E.R.C. Stat. & Regs. ¶ 31,214, at 30,349 (2006).

competitive advantage). Wholesale transmission customers captive to the transmission provider's system are particularly vulnerable to this kind of competitive harm.

Finally, the Commission "proposes that entities that engage in energy/asset management of generation on behalf of non-regulated affiliates of a franchised public utility be treated in a similar manner as the non-regulated affiliates." NOPR P 117. APPA and TAPS support this proposal, which is consistent with the recommendation above that the Commission examine energy management contracts to see whether capacity and/or energy marketed under such arrangements should be considered under the control of the provider of such services for purposes of the MBR test. *See* Part VIII.D.

XII. MODIFICATIONS TO CHANGE IN STATUS REPORT REQUIREMENTS

The NOPR takes up a number of issues regarding change in status reporting under Order No. 652 that the Commission had deferred from the change in status proceeding. NOPR PP 179-85. As a general principle, APPA and TAPS urge the Commission to prescribe reporting triggers that result in all significant changes in status being reported. The small burden imposed by submission of a status change report far outweighs the potential consumer harm from the non-reporting of otherwise significant changes.

A. Transmission Outages

While recognizing that transmission outages could affect, on a long-term basis, whether the seller satisfies the standards for MBR authority, the NOPR proposes not to require the reporting of transmission outages per se as a change in status. NOPR P 183. As a general matter, APPA and TAPS agree with the NOPR's approach, but urge that certain outages be reported to the Office of Enforcement ("OE") on a non-public basis and that the Commission preserve its authority to require change of status reports for other, significant outages.

The public reporting of some outages, especially a generation outage, could place those who rely upon the output of the unit at a disadvantage when they go into the market to purchase replacement power. In addition, at least some transmission outage information is (or should be) publicly available on OASIS sites, suggesting less of a need to impose a separate reporting requirement for such outages. Thus, rather than generic, public reporting of outages, the Commission should support the monitoring activities of its OE by requiring that all MBR sellers report significant outages of generation and transmission facilities to OE on a non-public basis.[92] Non-public reporting, especially of generation outages, is needed to protect those who depend upon the facilities subject to the outage from being taken advantage of in the marketplace if they need to procure replacement resources and/or transmission service. Based upon the reported information, OE should monitor the relevant markets for evidence of unusual activities that could reflect attempts by the seller or others (*e.g.*, power suppliers whose market power is increased by the loss of another market participant's generation) to exercise market power. Where there is suspicious activity, the Commission should investigate.

The Commission should also preserve its authority to create a "fail-safe" mechanism by identifying for specific MBR sellers designated generation and transmission facilities, extended or repeated outage of which could produce significant transmission constraints or reductions in the amount of generation available in that MBR

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[92] If such outages are not already being reported to market monitors in ISO/RTO regions, they should receive such reports as well.

seller's market(s). The Commission, in conjunction with an ISO/RTO market monitor (where one exists), could identify and designate in that seller's MBR authorization the key transmission facilities and/or generation units that are likely to increase competitive concerns regarding the MBR seller's potential exercise of market power if they go out of service. Because of the increased potential for market power harm associated with the outage of these facilities, the Commission could require such an MBR seller under the terms of its MBR authorization to report publicly as a change in status outages of these specified facilities.

B. Agreements Providing Control

The NOPR asks about reporting obligations associated with arrangements other than ownership or control of, or affiliation with, entities that own or control, generation or transmission facilities or inputs into electric power production. NOPR P 184. APPA and TAPS support a reporting obligation for all of the types of contractual arrangements that could confer control, as consistent with the discussion in Part VIII.D. above. These arrangements could provide an MBR seller with the means to determine whether capacity is offered into a market and whether a competitor can or will enter a market. They also create opportunities for sellers to coordinate their behavior with other competitors. As such, they should be reported. If they do not raise competitive concerns, the factors supporting that conclusion can be explained in the report.

Marketing alliances or joint operating agreements present obvious circumstances that can affect a seller's market position. For example, several years ago, Entergy joined forces with Koch Industries to form an electricity and gas products marketing alliance. It would have been untenable to claim that such an alliance was irrelevant to either

Entergy's or Koch's market positions.[93] Perhaps less obvious are tolling arrangements, for example, where a seller supplies fuel to a generating plant and thus controls its output. While the supplier of fuel may not be operating the plant, it controls the plants' production of energy for sale, thus affecting market outcomes. Such an arrangement is appropriately reported.

Another type of arrangement that should trigger reporting is a long-term maintenance agreement whereby an MBR seller or its affiliate (for example, a vertically integrated utility) performs maintenance for another seller's facility and has the ability to decide when such maintenance is performed. If the entity providing maintenance operates facilities in the same market (or has an affiliate that does so), its decisions about when to perform the maintenance (thereby possibly requiring an outage) could be influenced by its (or its affiliate's) sales activities in the market. If such arrangements pose no competitive concerns, this can be explained in the report.

C. Fuel Inputs

The NOPR also "solicits comments on whether ownership of any new inputs to electric power production, including fuel supplies, should be reportable." NOPR P 182. While acquisition of fuel itself should not trigger reporting, acquisition or control over companies that produce or deliver fuel, acquisitions of or affiliations (including through joint ventures) with production or transportation resources (including LNG facilities) are inputs into electric power production and can raise significant competitive concerns. *See San Diego Gas & Elec. Co.*, 83 F.E.R.C. ¶ 61,199 (1998) (gas/electric merger). Unlike

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[93] Indeed, the Federal Trade Commission investigated the marketing alliance and required changes in it. *In the Matter of Entergy Corp. & Entergy-Koch, LP*, FTC File No. 001 0172, Docket No. C-3998 (Jan. 31, 2001), *available at* http://www.ftc.gov/os/2001/01/entergydo.pdf (last viewed Aug. 2, 2006).

the fuel commodities themselves, the means of production or transportation of fuel are not so readily obtainable from alternative sources. While entry from new storage or transportation facilities/transporters is possible, such entry involves sufficient siting difficulties and capital requirements that it cannot be assumed to be timely, likely or sufficient to remove competitive concerns.

XIII. THE COMMISSION SHOULD NOT RELAX STANDARDS FOR MARKET-BASED PRICING OF ANCILLARY SERVICES

The NOPR proposes continuation of the Commission's current approach for pricing ancillary services, specifically, a requirement for a cost-based back-stop for ancillary services provided by a transmission provider, an Internet-based site for market-based pricing of third party provided ancillary services, and some market-based pricing of ancillary services in ISO/RTO markets. NOPR P 195. APPA and TAPS support staying the course in this realm. The fundamental problem is that ancillary services markets remain very much dependent upon control area operation and are closely connected to the operation of the transmission system. This is reflected, inter alia, in the Commission's policy of authorizing MBR for ancillary services outside a transmission provider's system. *Avista Corp.*, 87 F.E.R.C. ¶ 61,223, *order on reh'g*, 89 F.E.R.C. ¶ 61,136 (1999). Locational reserves requirements limit the geographic scope of potential suppliers. Capacity on automatic generation control ("AGC") cannot easily sell regulation service in its home market today and switch to sales in an adjoining market tomorrow. Nor can customers shop for such services. Thus, limitations of transmission and technology counsel against adopting short-cuts for assessing the appropriateness of market-based pricing of ancillary services.

APPA and TAPS urge caution for market-based pricing of ancillary services in ISO/RTO areas. Even if the Commission finds that conditions exist to permit market-based pricing of some ancillary services in some ISO/RTO-administered markets, such pricing would not be appropriate where vertically integrated utilities are also control area operators, such as in MISO and SPP, because the locational, control-area dependent nature of ancillary services increases the risk that control area operators will have market power.

CONCLUSION

Wherefore, the Commission should adopt a final rule that reflects the comments and changes APPA and TAPS propose above.

Respectfully submitted,

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