

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Wholesale Competition in Regions with )  
Organized Electric Markets )**

**Docket Nos. RM07-19-000  
and AD07-7-000**

**COMMENTS OF THE  
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION**

**September 14, 2007**

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Pursuant to the Advance Notice of Proposed Rulemaking (“ANOPR”) issued in this proceeding on June 22, 2007,<sup>1</sup> and the July 27, 2007 Notice of Extension of Time issued in these dockets, the National Rural Electric Cooperative Association (“NRECA”) respectfully submits its comments on the Commission’s potential reforms to improve the operation of organized wholesale electric markets.

**I. INTRODUCTION AND SUMMARY**

NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives, which provide retail electric service to over 39 million consumer-owners in 47 states. Kilowatt-hour sales by rural electric cooperatives account for approximately 10% of total electricity sales in the United States. NRECA’s members also include approximately 65 generation and transmission (“G&T”) cooperatives, which supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

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<sup>1</sup> 119 FERC ¶ 61,306 (2007), 72 Fed. Reg. 36,276 (July 2, 2007).

This fact shapes NRECA’s comments on the proposals contained in the Commission’s ANOPR. Nearly all of NRECA’s members are load-serving entities (“LSEs”) with a legal obligation to provide electric service to their member-owners—either other cooperatives (in the case of G&T cooperatives) or end-use customers (in the case of distribution cooperatives).

Some rural electric cooperatives generate the electricity they sell to their owner-members, but most rural electric cooperatives are net buyers of electricity. Overall, cooperatives purchase nearly half of their energy requirements at wholesale from other suppliers. Consequently, NRECA has supported the Commission’s efforts to encourage the development of competitive wholesale energy markets. Today, a number of NRECA member cooperatives operate within or are affected by organized electricity markets operated by Regional Transmission Organizations (“RTOs”) and Independent System Operators (“ISOs”). These cooperatives have a vital interest in the improved operation of organized wholesale electric markets.<sup>2</sup> In that light, NRECA offers the following comments on the Commission’s proposals in the ANOPR:

- NRECA and its members strongly support the use of demand response as an important cost-cutting and risk management tool. As it considers implementing new policies, the Commission should ensure that it does not sacrifice just and reasonable rates for the goal of achieving “competition.”

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<sup>2</sup> In this regard, NRECA has expended substantial resources to develop a “report card” on the nation’s RTOs, analyzing the performance of RTO markets and their operational elements. *The Regional Transmission Organization Report Card: Wholesale Electricity Markets And RTO Performance Evaluation* (2<sup>nd</sup> Ed.), prepared for NRECA by Mathew J. Morey, Laurence D. Kirsch, Brad Wagner, Bruce Chapman, Emilie McHugh, Christensen Associates Energy Consulting, LLC (August 20, 2007). Available at: [http://www.nreca.coop/Documents/PublicPolicy/RTO\\_RC\\_Final\\_071807\\_Revised.pdf](http://www.nreca.coop/Documents/PublicPolicy/RTO_RC_Final_071807_Revised.pdf).

- NRECA supports incorporation of demand response into markets to the extent that they can meet the same operational requirements as supply side resources.
- To ensure that wholesale demand response programs do not conflict with state energy policy or undermine existing LSE-operated demand response programs, the Commission should permit retail consumers to participate directly in wholesale markets only if the consumers: (i) are located in states and service territories that have established retail choice; and (ii) are served by a supplier other than a default supplier with a traditional obligation to serve at a cost-based regulated rate.
- The Commission should remove bid caps for demand response resources in emergencies but should not permit demand response to set the market clearing price. Bid caps should not be removed for supply-side resources. Broader proposals to remove caps would harm consumers and encourage anti-competitive behavior.
- The Commission should continue to address impediments to long-term contracting in organized markets. Consumers must not pay unjust and unreasonable rates for long-term power contracts.
- In implementing any reforms to market monitoring in RTOs/ISOs, the Commission should ensure that mitigation is not weakened. Careful Commission oversight over market monitoring is essential. Among other things, the Commission should ensure that market monitoring units

(“MMUs”) abide by a code of ethics and that market participants and the Commission have direct access to the market monitor’s reporting.

- The Commission cannot delegate its statutory authority to set rates under the Federal Power Act to market monitors.
- Although RTOs/ISOs should be independent, it is critical that they and their boards be accountable to their stakeholders, regardless of the structure of the board. This includes transparency and accountability with respect to the costs of the RTOs/ISOs.

## **II. DEMAND RESPONSE AND PRICING DURING POWER SHORTAGES**

### **A. NRECA and Its Member Cooperatives Strongly Support Demand Response.**

Electric cooperatives are strong supporters of demand response as a critical cost-cutting and risk management tool. Cooperatives are LSEs with an obligation to provide their consumers with reliable power at the lowest reasonable cost over the long term. To accomplish that, cooperatives engage in both risk and portfolio management on behalf of their members. Each cooperative directly or through a G&T or other power supplier puts together a portfolio of owned and contractual energy and capacity resources. Many cooperatives also obtain a portion of their power supply in RTO markets. Cooperatives treat demand response as an important part of their power supply portfolios. Demand response is a flexible hedge that helps permit cooperatives to shape their load, reduce contractual demand costs, reduce both generation and capacity costs, and reduce their costs and risks in wholesale markets.

Nationwide, cooperatives can control up to approximately six percent of their peak demand through demand response programs, including approximately 1,440 MW of

residential load control. Although cooperatives provide only about ten percent of the country's total energy sales, their combined residential demand response resources equal approximately 80% of the residential demand response capacity of all investor-owned utilities. Those cooperatives that are most actively using demand response can control 15%, 25%, even 50% of their peak demand across all customer classes. Cooperative demand response programs include direct load control, interruptible contracts, voluntary "share the savings" interruption programs, time-of-use rates, and control of customer-owned generation. Large numbers of cooperatives have also implemented programs that shift load off peak, such as heat storage and high-efficiency/large capacity water heaters with timers.

**B. The Commission Must Not Lose Sight of the Ultimate Goal – Keeping Electric Rates to a Just and Reasonable Level.**

NRECA supports efforts to encourage demand response in organized markets. As the Commission defines the role demand response should play in organized markets, it should recognize that demand response is an important tool that can help ensure that markets serve consumers by preserving reliability and minimizing the cost of electric service. It would be a serious mistake and violation of the Federal Power Act, however, if the Commission were to use demand response as a means of forcing consumers to change behavior for the benefit of wholesale markets, if the result is prices that are not just and reasonable.

NRECA has long supported wholesale electric competition when it drives prices down, forcing suppliers to be more efficient, and improving the quality of wholesale service. The goal of competition must be to make consumers better off by constraining the prices faced by consumers more effectively than regulation. If customers must

experience higher prices, greater volatility, and lower reliability for markets to be “competitive,” then the markets have been poorly designed and “competition” in that form is not in consumers’ best interest.

Cooperatives’ demand response programs demonstrably support competition and benefit consumers at the same time. These demand response programs benefit the individual consumers who have volunteered to participate in exchange for lower rates or other incentives. Importantly, those demand response programs also benefit the rest of the cooperatives’ consumers by providing the cooperative with a tool it can use to reduce the cost of its generation portfolio and its exposure to market risk. In turn, the cooperative can keep rates down for all of its consumers, including those whose demand may be inflexible. Those demand response programs also benefit the market as a whole by permitting the cooperative to reduce its aggregate wholesale demand in response to high wholesale market prices.

The Commission can certainly define a role for demand response in the wholesale markets that is as beneficial for all consumers as the programs that cooperatives administer. As discussed below, however, NRECA is concerned that some of the ANOPR’s proposals could turn the rationale for markets on its head: promoting the interests of “the market” at the expense of individual consumers and communities. Accordingly, as the Commission fashions its proposed rule, it should carefully refrain from supporting policies that it believes may help achieve competition but that will ultimately leave consumers paying more for the privilege of having it.

**C. Demand Response Should Be Subjected to Comparable Requirements as Other Supply Resources.**

NRECA supports the Commission's stated goal of facilitating the development of RTO/ISO rules that ensure the treatment of demand and supply resources on a comparable basis. ANOPR at P 35. Integrated properly, demand response can certainly enhance both market performance and the reliability of the transmission system. To obtain those benefits, however, demand resources must satisfy requirements for the provision of service that are fully comparable to the requirements applicable to supply resources. *Id.* While demand response should be integrated to the greatest degree practical, it should not receive preferential treatment and must not undermine reliability.

The Commission seeks specific comment on its proposal "to obligate each RTO or ISO to purchase demand resources in its markets for certain ancillary services, similar to any other resources, if the resources meet the necessary technical requirements and the resources submit a bid under the generally-applicable bidding rules at or below the market-clearing price . . ." ANOPR at P 59. NRECA believes it would be reasonable to do so if, as the ANOPR states, the demand resources truly meet the necessary technical requirements. Additionally, as noted by the Commission, demand resources should meet the RTO's or ISO's reasonable size, telemetry, metering, and bidding requirements. *Id.*

NRECA believes, however, that it would be premature for the Commission to impose upon RTOs and ISOs a "one-size-fits-all" rule for the technical requirements applicable to the use of demand-side resources as ancillary services. In the absence of Commission action, NERC's reliability standards should ensure that RTOs/ISOs adhere to a reasonably narrow band of minimum requirements. After the RTO/ISO system operators gain more experience with using demand-side resources for ancillary services,

the Commission may then consider setting universal minimum requirements. Until then, the Commission should “allow each RTO and ISO to propose its own minimum requirements” on demand-side resources that offer ancillary services, subject to the constraints that these requirements be consistent with reliability and be non-discriminatory among resources. ANOPR at P 61.

**D. The Commission Should Not Take Action That Would Undermine LSE Demand Response Programs.**

As the Commission is aware, NRECA has long been concerned about RTO proposals that would permit those retail customers that are served under traditional retail tariffs, directly or through an aggregator of retail customers (“ARC”), to bid demand reductions into the RTO’s markets. Such proposals may make sense for retail customers taking non-cost-based service from a competitive supplier. They do not, however, make sense for retail customers served under traditional retail tariffs.

Demand response is a critical risk and cost management tool for cooperatives and other LSEs. Demand response represents an important element of their existing resource management programs and helps them to maintain stable, affordable rates for their retail consumers over the long-term. Demand response programs are also closely integrated with existing retail power supply agreements, with certain rates available only to those customers willing to participate in utility demand response programs. Permitting individual consumers served under a traditional retail tariff to participate directly in the wholesale market could undercut both LSEs’ existing retail power supply contracts and their demand response programs in a number of ways. That could, in turn, raise costs and price volatility for the rest of the LSEs’ consumers. It would also inappropriately and unfairly permit those individual customers to benefit from both the long-term average

cost service provided by traditional LSEs and from the incremental benefits from direct participation in the short-term market.

In the ANOPR, at P 70, the Commission now proposes to require all RTOs and ISOs to amend their market rules as necessary to “allow smaller retail customers to combine their individual demand reductions into a larger block for bidding into the organized markets, *if permitted by state law*, without having to go through their LSE.” *Id.* at P 43 (emphasis supplied). The Commission also phrases this issue in the negative, proposing that the RTO’s or ISO’s demand response market rules “may not exclude a demand response bid from a third-party ARC that is not a LSE *unless state retail electric laws or regulations do not permit this.*” ANOPR at P 70 (emphasis supplied).

In these two statements, and throughout the ANOPR’s discussion of demand response, it appears that the Commission has recognized NRECA’s concern and has sought to address it to some degree. Importantly, the Commission should now explicitly clarify when direct retail participation in the wholesale market should and should not be permitted.

*Rather than turning on state “permission,” or prohibition, the issue should turn on the nature of the retail service being taken by the individual consumer.* If a customer is taking service from a retail choice supplier, and thus is exposed to wholesale market price risk, the customer should be permitted to hedge that risk by selling its demand response to an ARC or directly into the wholesale market. If, on the other hand, the customer is taking traditional retail service from an LSE, and the LSE is responsible for hedging risk on the customer’s behalf over the long-run, then it is the LSE that should

have the exclusive ability to participate in the wholesale market on that customer's behalf.

This clarification is important for a number of reasons. The first and most practical from the Commission's perspective is that state "permission" or the lack thereof is unlikely to be clear anywhere. In most if not all states, state law will be silent on the issue. State laws establishing retail service were not drafted with wholesale markets in mind. In states that never adopted retail choice, state laws governing retail service have not seen a major overhaul since the creation of RTOs and centralized wholesale markets. In fact, most state laws providing for retail choice also predate Day 2 centralized markets. Thus, state laws simply do not expressly provide that direct participation is permitted or prohibited. This is particularly true in territories served by cooperatives and municipal utilities because these utilities are not rate-regulated in most states, and because most states that have adopted retail choice for customers served by investor-owned utilities have left it to individual cooperatives and municipal utilities to decide for themselves whether to allow retail choice in their service territories. This lack of clarity could subject the Commission's proposed rule, if finalized without clarification, to litigation in every state and service territory. NRECA's proposed clarification would prevent this potential controversy.

The clarification NRECA recommends is also consistent with the Commission's goal of preserving state decisions concerning retail power supply policy. States that declined to adopt retail choice throughout the state made a conscious decision to retain the historical regulatory compact with LSEs. In exchange for the continued opportunity to earn a reasonable rate of return on prudent investments, the LSEs would continue to be

required to act prudently to provide consumers with power at the lowest reasonable cost over the long-term. In most cases, prudence requires, in turn, that LSEs engage in risk and portfolio management on behalf of their consumers including, often, the implementation of demand response programs. Where states declined to adopt retail choice, the states decided to leave risk management, including the use of demand response, to LSEs rather than individual consumers. Those states selected an insurance pool approach to power supply. By averaging costs across all consumers, the pool reduces the risks to any individual consumer. The pool as a whole also has the incentive to reduce long-run costs to all consumers by investing in energy efficiency and demand response – the equivalents of wellness programs, preventive healthcare, and early detection in the medical industry.

By contrast, those states that adopted retail choice chose to shift the obligation to address market risks to individual consumers. Consumers with retail choice may hedge those risks in the same way that utilities do, by developing a portfolio of resources including their own generation, contractual hedges such as a fixed cost arrangement with a competitive supplier if that is available, and demand response, *i.e.*, by altering their behavior in response to hourly market prices. These states have rejected the insurance pool approach. Each customer bears his or her individual risk, and his or her individual costs for health care – or in this case power. The healthier (those with off-peak demand) pay less, while those more susceptible to illness (those with on-peak demand) pay more. Those who are able to invest in preventive healthcare and early detection (energy efficiency and load control technologies) can lower their cost and risk further. Customers

that wish to hedge their risks can buy individual insurance – the premiums for which reflect their individual health (demand) profiles.

Some states left the decision whether to adopt retail choice to individual electric cooperatives and municipal utilities. State law permitted local consumers, through their locally governed utilities, to decide whether they preferred their utility to continue to perform risk and portfolio management on their behalf or whether they preferred to enter the market – with its inherent risks – themselves. Those that chose to leave the obligation to perform risk and portfolio management with their utilities made a decision to approach power supply collectively rather than individually. They chose to retain the insurance pool approach.

Clarification that direct participation in wholesale markets should be limited to consumers taking service from non-traditional competitive suppliers in territories with retail choice is necessary to preserve the decisions of these states and local communities. Permitting individual end users still served by traditional LSEs to participate directly in wholesale markets could effectively disrupt the LSEs' ongoing risk management efforts on behalf of all of their consumers by undermining the insurance pool approach adopted by those states and communities.

If the Commission does not provide this clarification, RTOs and ARCs would effectively be allowed to cherry pick the best load response resources out of existing LSE demand response programs. This would foreseeably (i) strand investments made to serve the cherry-picked consumers; (ii) discourage utilities from reaching out to those consumers by creating a risk of stranded investment; and (iii) eliminate the necessary efficiencies of scale and scope required for the utilities to reach the remaining consumers

who may not be attractive to aggregators but otherwise would be economic to reach in a more broad-based program.

Allowing RTOs/ISOs and ARCs to cherry pick LSE demand response resources would also deprive those LSEs of important resources used to keep rates down for all consumers. To continue the health-care analogy, this would be equivalent to permitting the healthiest members of the pool to avoid paying premiums – until they got sick. Whenever they chose, those customers could benefit from the low and stable rates enabled by the LSE’s risk management and portfolio management efforts – its pool activities – but the LSE and the pool would be deprived of the potential benefits that they would get from the ability to control the individual customers’ loads.

For these reasons, wholesale demand response programs should permit retail consumers to participate directly only if the consumers: (i) are located in states and service territories that have established retail choice; and (ii) are served by a competitive supplier – not a default supplier with a traditional obligation to serve at a cost-based rate.

Such an approach preserves critical state and local decisions about the nature of retail power supply and should lead to as much or more load response in wholesale markets as one that permits cherry picking. Such an LSE-based approach preserves the LSEs’ incentives to develop, market, and employ their own demand response programs.

**E. Effective Demand Response Need Not Be Tied to Price at the Retail Level.**

In discussing what it views as “remaining problems” with demand response in organized market, the ANOPR states that “[d]emand response is more effective when retail rates are tied to current wholesale market-clearing prices” and that “[a]n effective way for demand to respond to price is at the retail level[.]” ANOPR at P 48. NRECA is

concerned that the types of time-based retail rates that the ANOPR cites as examples of ways to achieve this link (*e.g.*, real-time pricing, critical peak pricing, *etc.*), while perhaps currently in vogue, may not be the best approach. NRECA urges the Commission to recognize the value of existing traditional demand response programs of many rural electric cooperatives, which have been very effective nationwide and to explicitly forego any action that would damage these demonstrably effective programs.

At the Commission's January 2006 technical conference on demand response, Dr. Goldman from the Lawrence Berkeley National Labs testified that real-time pricing programs have garnered approximately a one percent peak reduction.<sup>3</sup> More recently, Ahmad Faruqui from The Brattle Group estimated that aggressive time-based pricing programs could achieve about a five percent peak reduction nationwide.<sup>4</sup> By contrast, NRECA's members have obtained an average six percent peak reduction with utility-operated demand response programs including some more traditional time-based rates as well as direct load control, interruptible contracts voluntary "share the savings" interruption programs, and control of customer-owned generation.<sup>5</sup> While some have touted the success of a critical peak pricing ("CPP") pilot program in California,<sup>6</sup> it is no wonder that customers used less power with CPPs, at times, approaching 90 cents/kWH

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<sup>3</sup> *Assessment of Demand Response Resources*, Docket No. AD06-2, *et al.*, Technical Conference Tr. at p. 17 ll. 23-25 (January 25, 2006).

<sup>4</sup> Ahmed Faruqui, *et al.*, *The Power of Five Percent: How Dynamic Pricing Can Save \$35 Billion in Electricity Costs* at p. 4 (May 16, 2007), available at: <http://www.energetics.com/MADRI/pdfs/ArticleReport2441.pdf>.

<sup>5</sup> *Assessment of Demand Response Resources*, Docket No. AD06-2 *et al.*, Statement of Jay Morrison for the Technical Conference on Demand Response in at page 1 (January 25, 2006).

<sup>6</sup> *See, e.g.*, Ahmed Faruqui & Robert Earle, Demand Response and Advanced Metering, Regulation, Vol. 29 No. 1, Spring 2006, available at: <http://www.cato.org/pubs/regulation/regv29n1/v29n1-3.pdf>.

for energy alone.<sup>7</sup> That is more than ten times the national average all-in price of 8.85 cents/kWh for retail power in 2006.<sup>8</sup>

The Commission should not pursue market designs that are based on consumer acceptance of higher prices and higher price volatility. No cooperative has ever told NRECA that its consumers were asking to be exposed to wholesale market risks. Instead, consumers are looking to their cooperatives to engage in long-term planning and risk management in order to mitigate the effect of market volatility on their retail rates. While demand response certainly is one hedge that cooperatives use to manage their price and market risks, they do not believe that either wholesale or retail consumers should be involuntarily subjected to unmitigated market volatility simply for the sake of promoting short-term economic efficiency. That approach to market design puts markets ahead of consumers.

**F. The Commission Needs to Overhaul Its System of Pricing for Deviations.**

The Commission seeks comment on whether an RTO/ISO should assess a deviation charge for a day-ahead to real-time load reduction differences when there is no system emergency. ANOPR at P 67. NRECA believes this is an important question but one that needs to be addressed in a broader context – one which would examine whether

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<sup>7</sup> See, e.g., Pacific Gas and Electric Company, Schedule E-3 – Experimental Residential Critical Peak Pricing Service, Revised Cal. P.U.C. Sheet No. 26005-E, available at: <http://www.pge.com/tariffs/pdf/E-3.pdf> (“super-peak” rates ranging from 67.4 cents/kWh to 90.8 cents/kWh); San Diego Gas & Electric Company, Schedule EECC-CPP, Sheet 1 – Electric Energy Commodity Cost Critical Peak Pricing, Revised Cal. P.U.C. Sheet No. 20099-E, available at: [http://www.sdge.com/tm2/pdf/ELEC\\_ELEC-SCHEDS\\_EECC-CPP.pdf](http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC-CPP.pdf) (summer rates during certain CPP event days of \$1.32/kWh).

<sup>8</sup> Energy Information Administration, Table 5.3, Average Retail Price of Electricity to Ultimate Customers: Total by End-Use Sector, 1993 through May 2007 (Aug. 15, 2007), available at [http://www.eia.doe.gov/cneaf/electricity/epm/table5\\_3.html](http://www.eia.doe.gov/cneaf/electricity/epm/table5_3.html).

deviation charges properly reflect costs. The mispricing of deviations in system emergencies is indicative of the larger problems with deviation charges, and the Commission should undertake a more thorough review of the economic efficiency implications of how these charges are determined, as it considers doing in the ANOPR at P 67. In any event, NRECA believes the price of the deviation charge when the deviation is negative should not be a penalty, but, instead, should be based on the normal cost of service. RTO Day 2 market designs are very complex and they each have unique characteristics. While NRECA supports market pricing policies that do not discourage demand response when it is needed, pricing policies should not be so generous as to encourage market gaming through demand response pricing rules. Therefore, the Commission should strive for this balance of principles and regional flexibility as it approaches this problem.

**G. The Commission’s Proposed Modification of RTO/ISO Mitigation Rules Would Inappropriately Punish Demand for Failure of Supply.**

The Commission proposes to modify RTO/ISO mitigation rules “to allow the market price to better reflect the value of lost load in an emergency situation.” ANOPR at P 75. NRECA would support removal of bid caps for demand response resources during emergency situations, provided that those higher bids for demand response do not set the market clearing price for all resources. This approach would encourage additional demand response by allowing demand response resources to obtain a higher price for their response during emergencies. And, by differentiating between the price received by demand resources and generation resources, it would appropriately treat demand response in these out-of-market situations as an operational tool for preserving reliability rather than as a pure market participant. The higher price paid for demand response resources

could save customers the even higher cost that would be incurred as a result of brown-outs or cascading outages.

An alternative rule that would remove bid caps for demand response resources at all times would be unnecessary and excessively costly for consumers. During periods when there is adequate supply, there would be no need to remove the bid caps for demand response. When supply becomes constrained, and market-clearing prices rise, however, short of an emergency, there is clearly a serious problem on the supply side that should be addressed by the Commission. Raising the bid caps for demand response resources in that situation increases costs for consumers, does not solve the underlying serious market issues, and actually masks the underlying supply-side problems.

The worst-case scenario would be an alternative rule that would either remove bid caps altogether during emergencies and/or scarcity situations or that would allow demand response bids to set the market clearing price in those situations. Such a rule would actually encourage behavior that creates shortages or “emergencies” by allowing generators to profit from those adverse conditions. The bid caps are in place because the markets are subject to the potential exercise of market power. That means that market participants have the ability and the incentive to create artificial shortages and artificially high prices. The Commission was only authorized to approve the caps under the FPA because they were necessary to ensure that rates remained just and reasonable under those conditions. It would not be sensible to adopt bid caps in response to potential market failures but then to remove the bid caps when that potential is realized and the market actually fails. The fact that unjust and unreasonable rates cause customers to use less power does not somehow make the rates just and reasonable.

Such a rule would also improperly punish consumers for failure of supply. In the guise of advancing competitive markets, such a rule would institute value-of-service pricing for a vital commodity, where demand has not been shown to be as elastic as the Commission seems to believe. In this regard, NRECA agrees with the dissenting opinion of Commissioner Kelly:

Before the Commission considers whether to pursue such market rule modifications, I think it is important to address other barriers that may significantly restrict demand response participation. For example, the FERC Staff Demand Response Assessment concluded that the technologies needed to support significant deployment of demand resources, such as advanced metering, have little market penetration. Without the necessary technology already in place that would allow demand resources to respond to price signals in wholesale or retail markets, it is unclear how quickly they could develop the ability to respond after energy bid caps or market-wide caps are raised or eliminated. In other words, the technology and associated demand response capability must be in place before we consider raising or eliminating these price caps. Otherwise these higher energy prices may not elicit any demand reduction in a fashion capable of disciplining those prices and keeping them just and reasonable. In addition, rather than asking questions in this ANOPR on how to value demand response, I think the Commission should have proposed a compensation method and postponed consideration of modifying market power mitigation rules until after the valuation issue had been addressed.<sup>9</sup>

As discussed above, NRECA believes that markets should be designed to serve consumer interests. Competition should be pursued to the degree that it serves to drive prices down and increase reliability for consumers as compared to regulation. If a market design cannot “work” unless it increases costs to consumers or reduces reliability, then it should not be adopted.

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<sup>9</sup> 119 FERC ¶ 61,306 (Kelly, Commissioner, *concurring in part and dissenting in part*).

NRECA is concerned that the ANOPR's proposal to remove bid caps too closely reflects the view described by Professor Frank A. Wolak in a recent paper<sup>10</sup> that the ultimate goal of markets is to achieve market efficiency, which will be achieved when "retail prices . . . allocate the available supply to final consumers willing to pay the market-clearing price."<sup>11</sup> NRECA does not agree with Professor Wolak that political and regulatory efforts to protect consumers from high prices and volatility are a problem that must be removed before markets can work.<sup>12</sup> While NRECA agrees with Professor Wolak that wholesale electric markets are inherently subject to market power on the supply side, NRECA firmly opposes Professor Wolak's proposed solution: deliberately exposing customers to that market power. Professor Wolak explains paradoxically that regulators can only eliminate market power if generators are permitted to exercise that market power to its fullest extent and if retail customers are directly exposed to those inflated wholesale prices.<sup>13</sup> Only when prices reach \$5,000-\$100,000/MWh, he argues, will retail customers feel enough pain to provide enough demand response to mitigate prices down to a level less reflective of market power.<sup>14</sup>

Prices reaching upwards of \$100,000/MWh cannot be just and reasonable, and NRECA hopes the Commission does not believe that such a market design would satisfy the FPA's requirement that rates be just and reasonable. Yet, if the Commission removes the bid caps at exactly the times when market power can most effectively be exercised

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<sup>10</sup> *Managing Demand-Side Economic and Political Constraints on Electricity Industry Re-structuring Processes* (June 2, 2007), by Frank A. Wolak, Department of Economics, Stanford University, available at <http://scid.stanford.edu/events/IndiaJune2007/DevelopmentResearch/Wolak.pdf>.

<sup>11</sup> Wolak at 2.

<sup>12</sup> *See, e.g.*, Wolak at 3 (describing as a "problem" the Commission's determination that market prices reflecting the exercise of unilateral market power by suppliers are unjust and unreasonable).

<sup>13</sup> *See id.*, at 3-4.

<sup>14</sup> *Id.* at 22.

(when supply is scarce), what else could be expected to happen? Even Professor Wolak concedes that there is an “explicit regulatory conflict” between removal of bid caps to encourage “efficient” demand response and the Federal Power Act’s prohibition against unjust and unreasonable rates.<sup>15</sup>

### **III. LONG-TERM POWER CONTRACTING IN ORGANIZED MARKETS**

#### **A. Customers Should Pay Just and Reasonable Rates for Long-Term Power Contracts.**

In its discussion of factors affecting contracting decisions by buyers and sellers, the ANOPR states that sellers claim “buyers simply do not want to pay the long-term cost of power.” P 87. That claim is inaccurate. Buyers in organized markets may be reluctant to pay an unreasonably high *price* for long-term power that is based on short-term or spot market clearing prices. However, many LSEs would, in fact, be willing to pay a price for long-term power that is based on long-term costs, and that takes into account the long-term risks that they assume as buyers. It is not clear yet what can be done to address this seeming impasse, but it does seem to raise fundamental market design questions that will eventually have to be resolved.

Even the definition of what constitutes “long-term” varies greatly between buyers and sellers, and particularly within and without organized markets. Typically in organized markets a long-term contract is one to three years, while in bilateral markets the definition is generally ten to twenty years – or even longer. Importantly, when viewed from the important perspective of infrastructure development and financing, it is the bilateral market definition of long-term that assists and encourages needed infrastructure investment. Wall Street would be hesitant to finance a generation developer backed by a

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<sup>15</sup> *See id.* at 4.

three-year contract. Such is not the case with a ten- to twenty-year contract. There are many examples in the bilateral markets of these long-term ten-to-twenty year contracts underpinning the development and financing of new infrastructure. While credit concerns are often mentioned as a reason for the shorter “long-term” contracts available in the organized markets, that problem largely arises from the use of standard trading contracts that are ill-suited use to longer term physical delivery arrangements. The greater problem is the lack of sufficient entry in organized markets. Entry is too slow and uncertain to drive the price for long-term resources down towards the cost of the resources.<sup>16</sup> The opportunity for low-cost base-load resources to benefit from the dark spread in the organized spot markets is too valuable for the owners of those resources to enter into long-term contracts reflective of the cost of those resources themselves.

There are a number of other challenges that will have to be addressed before adequate long-term contracting will be possible. The Commission has recognized and begun to address many of them in other dockets. Significant issues are the lack of adequate transmission capacity<sup>17</sup> and adequate long-term transmission rights<sup>18</sup> to ensure reliable delivery of power from long-term contracts at a known and reasonable cost.

Another challenge is the continuing lack of certainty concerning the shape and scope of the centralized markets. Rather than focusing on fixing the existing markets,

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<sup>16</sup> See Robert McCullough, *Looking for the Voom*, (June 26, 2007) available at: <http://www.appanet.org/files/PDFs/LookingfortheVoom.pdf> (arguing that Professor Hogan’s centralized market models are much less effective than the WSPP bilateral market at ensuring that counter parties are able to enter into long-term contracts to support construction of adequate generation).

<sup>17</sup> *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890 at P 58, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007).

<sup>18</sup> *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681 at PP6-10, 71 Fed. Reg. 43,564 (Aug. 1, 2006), FERC Stat. & Regs. ¶ 31,226 (Order No. 681), *order on reh’g*, Order No. 681-A, 117 FERC ¶ 61,201 (2006)).

RTOs continue to seek authority to operate new markets for capacity and for ancillary services.<sup>19</sup> The Commission should ensure that RTOs put their efforts into clarifying and simplifying their existing systems. Regardless of the theoretical short-term efficiencies that might be available, the Commission and the RTOs should refrain from creating greater cost and greater uncertainty through the expansion of their market activities.

#### **IV. MARKET MONITORING POLICIES**

##### **A. Changes in the Character of Market Monitoring Units Should Not Weaken Mitigation.**

The Commission states (at P 118) that it believes that this proceeding is not the appropriate forum to address issues of market power and mitigation. Of course the Commission can exercise its discretion as to what issues to address in any particular docket. NRECA would caution, however, that the Commission should not lose sight of market mitigation issues and should not presume that the changes it adopts in this proceeding will be sufficient to ensure adequate market mitigation. The ANOPR states (at P 119) that RTOs and ISOs themselves can more properly monitor operational activities affecting the market. But as the recent testimony of the market monitor for PJM Interconnection, L.L.C. (“PJM”) demonstrates,<sup>20</sup> the Commission cannot assume that RTOs and ISOs will be quick to highlight the flaws in their markets that have permitted abuse of market power.

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<sup>19</sup> See, e.g., *PJM Interconnection, LLC*, Docket Nos. EL05-1410-000 and EL05-148-000 (August 31, 2005) (filing to implement its new Reliability Pricing Model); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER04-691-065, Application of Midwest Independent Transmission System Operator, Inc. Pursuant to Section 205 of the Federal Power Act (October 27, 2005) (filing to amend and clarify certain provisions of MISO’s Real-Time revenue sufficiency guarantee).

<sup>20</sup> See Testimony of Dr. Joseph Bowring, Transcript of April 5, 2007 Technical Conference in Docket AD07-8-000, at p. 75, ll. 18-20 (“PJM views us [market monitors] primarily as employees who are responsible to management, rather than being responsible to provide independent views.”); *id.* at p. 93, ll. 5-7 (it is “very difficult to [be critical of the RTO/ISO] if you are an employee, if you are criticizing the person that fills out your performance review.”).

Market monitoring and mitigation regimes were critical elements in the original design and operation of existing RTO/ISO markets. Among other things, fundamental changes in the use of the existing physical infrastructure from serving individual companies to centralized markets made this essential. Those issues relating to physical infrastructure that existed at that time are just as relevant now, and maybe even more so, as indicated by continually rising congestion costs in the RTO markets.

The Commission also relied heavily on the existence of RTO/ISO mitigation in its recent Final Rule addressing market-based rate authorizations. There the Commission held that market-based rate sellers:

can incorporate the mitigation they are subject to in RTO/ISO markets or RTO/ISO submarkets with Commission-approved market monitoring and mitigation as part of their market power analysis. For example, if a market power analysis shows that a seller has local market power, the seller may point to RTO/ISO mitigation rules as evidence that this market power has been adequately mitigated. We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated.<sup>[21]</sup>

Similarly, the Commission “will consider an existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket.”<sup>22</sup>

Accordingly, it is that much more critical that the existing RTO/ISO mitigation programs not be weakened. NRECA urges the Commission to remain vigilant against market power and to consider – in whatever proceeding it believes is appropriate –

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<sup>21</sup> *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Final Rule, Order No. 697, 119 FERC ¶ 61,295 (2007), at P 241.

<sup>22</sup> *Id.* at P 242.

requiring independent review of RTO/ISO operational activities, including any market mitigation efforts. No form of RTO/ISO market monitor can satisfy the Commission's obligation to protect consumers against the exercise of market power.

**B. Market Monitor Personnel Should Be Required To Abide by Ethical Standards.**

NRECA supports the Commission's proposal (at P 120) to adopt ethical standards for personnel of MMUs. It is impossible to completely insulate market monitoring personnel from conflicts of interests and potential coercion. The Commission's proposal to prohibit market monitoring personnel from having a financial interest in any market participant is a logical first step in establishing ethical standards and should be included in any standardized code of ethics. The Commission should also ensure that any code of ethics should provide for civil penalties for violations by market monitoring personnel. Such a regulation would be consistent with the Commission's expanded civil penalty authority granted in the Energy Policy Act of 2005.<sup>23</sup>

**C. The Commission Should Require Greater Information Sharing.**

NRECA supports increased information sharing as a means of promoting transparency in RTO/ISO markets, as well as increasing the ability for oversight of the MMU's performance in monitoring the RTO's/ISO's administration of its tariff. NRECA recognizes that there are countervailing confidentiality concerns when disclosing commercially sensitive information. These concerns can, however, be addressed through appropriate confidentiality agreements and, where necessary, redaction of a market participant's identity (so as not to reveal participant-specific offer of cost-data). These measures, coupled with the Commission's other regulations on market manipulation,

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<sup>23</sup> Energy Policy Act of 2005, Pub. L. No. 109-58, § 315 (2005) (codified at 15 U.S.C. 717c-1).

would help eliminate the Commission’s collusion concerns. In short, these concerns are better addressed on a case-by-case basis rather than through a rule of general applicability limiting access to much-needed MMU information.

Reporting transparency is of utmost importance in order for the MMU to be perceived as a neutral and objective monitor of markets, the tariff, and market behavior, including the behavior of RTO management in administering the OATT. Market participants must be assured that they are privy to all substantive findings made by the MMU and not merely the recipient of the RTO’s or ISO’s “spin” on the situation. Only through access to the MMU’s direct findings and the underlying data can the public be confident the MMU is doing its job competently. Transparency, in short, leads to accountability. It is therefore particularly important that the Commission adopt its proposal (at P 115) to require MMUs to inform the Commission and other interested stakeholders of all MMU recommendations for changes to rules or the OATT. For the same reason, NRECA supports the Commission proposal (at P 116) to require the reporting of violations of Commission-approved rules and regulations (such as the Codes of Conduct and Standards of Conduct).

**D. While Strengthening MMU Independence Is an Important Goal, So Too Is Ensuring Proper Oversight of the MMU’s Market Monitoring.**

The Commission seeks comments (at P 108) on its proposal to achieve independence for MMUs to perform their market monitoring functions. The Commission correctly notes in the ANOPR (at P 107) that achieving the aim of MMU independence “raise[s] complex concerns” and “require[s] a careful weighing of the needs of various interests and constituencies.” NRECA supports the Commission’s goal of MMU independence. The MMU cannot be subservient to RTO management. Regardless of

whether it is located within or outside of the RTO, the MMU must have direct access to both the RTO's board of directors and the Commission. It must be able to report its findings without editing or redaction by RTO management.

Moreover, NRECA believes that the Commission must perform a crucial oversight function in order to both ensure actual MMU independence and to maintain accountability and high-quality market monitoring performance. NRECA therefore recommends that the Commission perform periodic audits of the quality of the market monitor's reports and investigations. Having market monitors report their findings directly to the Commission will aid this process.

Finally, NRECA supports increased information exchange as a critical element of enhanced oversight and encourages the Commission to promote information sharing to the greatest extent possible. If the MMU's findings *and the underlying data* are both available to state and federal regulators and to stakeholders (subject to appropriate confidentiality agreements and delays), those outside parties can help to maintain MMU independence by reviewing and independently confirming the MMU's conclusions. If the MMU's findings are consistently biased towards management or any individual stakeholder or sector, the bias will become immediately apparent to everyone in the industry. Transparency of the underlying data is critical to achieve this result. If regulators and stakeholders have access only to the MMU's conclusions, they will have no basis on which to evaluate their credibility and sufficiency.

**E. The Commission Cannot Delegate to Market Monitors the Power To Review and Set Rates Under FPA Sections 205 and 206.**

The ANOPR expresses concern that an MMU's performance of mitigation functions can compromise its independence in evaluating and reporting on market

performance. ANOPR at P 118. NRECA has a different concern with the MMU's performance of mitigation functions. It appears at times that the Commission may have, without statutory authority, delegated its authority and obligation to review and set wholesale power rates under Sections 205 and 206 of the Federal Power Act.<sup>24</sup>

This problem was particularly apparent in a recent statement by Dr. Joseph Bowring in the PJM MMU report on RPM.<sup>25</sup> In that report, Dr. Bowring stated that the MMU calculated the derived offer caps based on submitted data, which were applied to all sellers, because all participants in the RPM auction failed the market structure tests. PJM MMU Report at 1. Dr. Bowring concluded in the report:

All participants in the RPM auction failed the market structure tests with the result that offer caps were applied to all sellers. Based on these facts, the MMU concludes that the results of the 2007-2008 RPM auction were competitive.

*Id.* The irony of that statement should be immediately apparent to any observer. The MMU concluded that every bidder in the RPM market had the ability to exercise market power. And yet, the MMU claimed that the market was competitive. In fact, the prices arising from the RPM market were not set by the market. The prices were set by the MMU, using confidential data from each bidder. NRECA is not suggesting that

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<sup>24</sup> See, e.g., *Elec. Power Supply Ass'n v. FERC*, 391 F.3d 1255, 1261 (D.C. Cir. 2004) ("FERC's delegated authority does not include administration of the Sunshine Act. The Sunshine Act is a statute of general applicability governing FERC and all other federal agencies within its compass. FERC has no authority whatsoever to change the terms of the Act; rather, FERC must conform its regulatory activities to comply with the overriding terms of the Sunshine Act."); *United States Telecom Ass'n v. FCC*, 359 F.3d 554, 565 (D.C. Cir. 2004) ("When an agency delegates authority to its subordinate, responsibility--and thus accountability--clearly remain with the federal agency. But when an agency delegates power to outside parties, lines of accountability may blur, undermining an important democratic check on government decision-making); *Coalition for Fair & Equitable Regulation of Docks v. FERC*, 297 F.3d 771, 779 (8th Cir. 2002) (finding no unlawful delegation of power because FERC retained the right to require modification of the program).

<sup>25</sup> *Analysis of the 2007 – 2008 RPM Auction*, PJM Market Monitoring Unit (August 16, 2007) ("PJM MMU Report"), available at <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20070820-analysis-2007-2008-rpm-auction.pdf>.

mitigation be weakened, but that *the Commission* must fulfill its statutory obligation to ensure just and reasonable rates.

The Courts have been clear that the Commission can only rely on competitive markets to ensure that rates are just and reasonable under very specific conditions.<sup>26</sup>

Here, the MMU made it clear that those conditions did not exist. The MMU found that:

- The PJM Region, while passing the market share and HHI screens, failed the three pivotal supplier screen, and thus failed the preliminary market structure screen. The PJM Region also failed the two pivotal supplier test and the one pivotal supplier test. *Id.* at 2.
- The Eastern Mid-Atlantic Area Council (“EMAAC”) locational deliverability area (“LDA”) and the Southwestern Mid-Atlantic Area Council (“SWMAAC”) LDA failed all three screens. EMAAC had an HHI of 2155 and SWMAAC had an HHI of 49.8%. Both LDAs also failed the two pivotal supplier test and the one pivotal supplier test. *Id.* at 2-3.

As the Ninth Circuit has explained, if markets are not competitive, then the Commission cannot justify a departure from cost-based rates.<sup>27</sup> Yet, in this case, instead of relying on the market to drive down prices to competitive levels, the Commission

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<sup>26</sup> *Public Utility District No. 1 v. FERC*, 471 F.3d 1053, 1081 (9th Cir. 2006) (“...recent circuit decisions support the following conclusion: Market-based rate authority provides a meaningful opportunity for prior review and approval of rates under the FPA, an essential prerequisite to the *Mobile-Sierra* mode of rate review, *only* insofar as FERC implements and uses an effective oversight mechanism *after* the market-based rate authorization is initially granted. Only then can FERC meet its statutory duty to ensure that *all* rates are ‘just and reasonable.’); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1012 (9th Cir. 2004) (“...approval of [market-based] tariffs was conditioned on the existence of a competitive market. Thus, market-based applications were approved only if FERC made a finding that “the seller and its affiliates [did] not have, or adequately [had] mitigated, market power.” (internal citations omitted).

<sup>27</sup> *Lockyer*, 383 F. 3d at 1012.

instead relied on the MMU to establish bid caps for each bidder based on the MMU's assessment of the bidder's opportunity costs as determined through data available only to the MMU. The individual bid caps were not filed with the Commission as rates. The caps were not subject to litigation at the Commission as cost-based rates would be – even though the bid caps were supposedly based on cost. The caps were not subject even to post-hoc review by other market participants because the data on which they were based was confidential. The individual bid caps, which were determinative of the ultimate RPM prices, were not subject to any review: they were subject only to the MMU's discretion.

## **V. RESPONSIVENESS OF RTOS AND ISO**

### **A. The Commission Should Provide for Increased RTO/ISO Cost Containment Responsibility as a Part of any Proposal To Increase Responsiveness of RTOs and ISO.**

The Commission identifies what it refers to as a “tension” between RTO/ISO goals of independence and stakeholder responsiveness. ANOPR at P 135. This is not a new issue, and NRECA welcomes the Commission's renewed focus on this issue. In its comments on the Commission's proposed changes to the accounting and financial reporting requirements for and oversight of RTOs and ISOs, NRECA cautioned that accountability should not be sacrificed in the name of independence.<sup>28</sup> NRECA stressed that independent governance must not relieve an RTO/ISO from cost containment responsibility. Many stakeholders now believe that the costs they bear in belonging to an RTO/ISO or participating in an RTO/ISO market are not justified by the accompanying

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<sup>28</sup> See Comments of the National Rural Electric Cooperative Association on Notice of Inquiry, Docket No. RM04-12-000 (Nov. 8, 2004) at 7-8.

benefits.<sup>29</sup> The Commission should remember that organized markets should only be instituted if they deliver net savings/benefits to consumers.

NRECA is concerned that the Commission’s proposal to improve responsiveness by providing stakeholders with increased access to their RTO/ISO board of directors fails to address the important issue of cost containment. Any proposed rule that results from this proceeding should address ways to ensure that RTOs/ISOs operate in the most cost-effective and responsible fashion. NRECA believes that the Commission should seek input from stakeholders on ways of holding RTOs/ISOs accountable for their decisions – including expenditure decisions – while retaining independence.

**B. Regardless of the Structure of the RTO/ISO Board, It Should Be Accountable to Its Stakeholders.**

NRECA agrees with the Commission that “[c]ustomer responsiveness must begin with the RTO/ISO board.” ANOPR at P 147. NRECA’s members have different views on whether a hybrid board would be an appropriate way to achieve better responsiveness to stakeholders, and NRECA is not commenting here on that issue.

One thing NRECA’s members do agree on, however, is that effective communication between the RTO/ISO board and its stakeholders is essential, regardless of how the board is structured. Stakeholders must be assured that the RTO/ISO board is listening to their concerns and addressing these concerns. Having board members participate actively in the substantive committees is one way that communication between the board and stakeholders can be improved.

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<sup>29</sup> See, e.g., American Public Power Association, *Restructuring at the Crossroads, FERC Electric Policy Reconsidered* (Dec. 2004) at 14-15, available at <http://www.appanet.org/files/PDFs/APPAPaperRestructuringatCrossroads1204.pdf>.

Another thing that NRECA's members agree on is that the question of the appropriate structure of an RTO/ISO board is best left to the membership to decide. The membership should have a say in whether an existing RTO/ISO board structure is working well or if the structure needs to be overhauled completely, or perhaps modified to improve communications.

Finally, it may be worth observing that none of the forms of governance of RTOs/ISOs now in place or under serious discussion provides a substitute for vigorous regulation of their jurisdictional activities. Nor is any form of RTO governance likely to form a basis for light-handed regulation of the activities of these transmission monopolies controlling access to huge regional power markets out of unwarranted deference to stakeholder or other processes that are not disciplined by either regulation or market forces.

## **VI. CONCLUSION**

NRECA commends the Commission for initiating this inquiry and requests that the Commission to take its comments into consideration as it moves forward in fashioning a proposed rule.

Respectfully submitted,

NATIONAL RURAL ELECTRIC  
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September 14, 2007