

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

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

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

**COMMENTS OF THE
LARGE PUBLIC POWER COUNCIL
IN RESPONSE TO
ADVANCE NOTICE OF PROPOSED RULEMAKING**

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The Large Public Power Council (“LPPC”) hereby submits its comments on the Advance Notice of Proposed Rulemaking (“ANOPR”) issued by the Federal Energy Regulatory Commission (“Commission”) or (“FERC”), in these proceedings on June 22, 2007 and published in the Federal Register on July 2, 2007.¹

I. INTRODUCTION AND EXECUTIVE SUMMARY

A. LPPC

LPPC represents twenty-four of the nation’s largest publicly-owned power systems.² LPPC members provide reliable, low-cost electric service to most of the more than 40 million people served by public power. LPPC members belong to the American Public Power Association (“APPA”) and speak for the larger, asset owning members of the municipal

¹ 72 Fed. Reg. 36276 (July 2, 2007).

² LPPC’s members are Austin Energy, Chelan County Public Utility District No. 1, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Massachusetts Municipal Wholesale Electric Company (“MMWEC”), Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Platte River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, South Carolina Public Service Authority (Santee Cooper), Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities.

community. LPPC supports the comments filed by APPA in this docket. Together, LPPC members own and operate over 66,000 megawatts of generation capacity and approximately 33,000 circuit miles of high voltage transmission capacity. LPPC members are governed by state and local laws establishing that their core obligations are to provide reliable service to native load customers at the least possible cost.

With members that are both transmission providers and transmission customers on third-party systems, LPPC offers a broad perspective on transmission policy. LPPC member systems include those that are operated within RTO/ISO systems and those that are outside. Among those members outside RTOs/ISOs are a number that move power through RTO/ISO systems, and purchase and sell power in markets operated by RTOs/ISOs.

LPPC has been a strong advocate of a wholesale open access regime under which transmission capacity not needed to meet utility obligations is made available to the marketplace on a non-discriminatory basis. LPPC members uniformly make such surplus transmission capacity available, some by way of participation in RTO/ISO operations,³ some under open access reciprocity tariffs⁴ and others under locally regulated tariffs designed to meet customers' local needs.

B. EXECUTIVE SUMMARY

LPPC vigorously urges the Commission to undertake a full review of what works and doesn't work with respect to organized wholesale markets. LPPC shares with APPA the conviction, expressed in comments filed contemporaneously in this docket, that much has gone wrong in RTO/ISO markets since their inception nearly a decade ago. The evidence to which

³ Long Island Power Authority and the New York Power Authority participate in the New York ISO. MMWEC is a member of ISO-NE. Austin Energy, Lower Colorado River Authority and CPS Energy participate in ERCOT and provide service under the ERCOT tariff.

⁴ Colorado Springs Utilities, Orlando Utilities Commission, Salt River Project and Santee Cooper.

APPA points suggests that organized markets have not worked as anticipated in controlling power costs and eliciting new supply, and, in fact, have helped create conditions that have allowed a substantial transfer of wealth from customers to the generation sector in certain markets. With that evidence in mind, while LPPC appreciates the Commission's interest securing feedback on those issues it has identified in the ANOPR, LPPC agrees with APPA that a broader inquiry than now contemplated by the ANOPR is warranted. APPA's input also provides an important perspective on those issues on which the ANOPR does elicit input, including particularly the Commission's inquiry into measures that should be taken to improve RTO/ISO responsiveness. Refocusing RTOs on means to ensure net consumer benefits must be the Commission's priority.

LPPC's input on those issues the Commission specifically identifies is as follows:

- **Demand Response:** While LPPC is squarely behind the Commission in its promotion of demand resources within RTOs and ISOs, LPPC is vigorously opposed to proposals which would permit generation prices to rise above rate cap levels in scarcity situations. The Commission should focus its efforts on compensation directly to demand resources, but risks violating its statutory responsibility to establish just and reasonable rates if it releases generation price caps at precisely the time they are most needed.
- **Long-Term Power Contracting:** LPPC supports the Commission's proposal to call upon RTOs and ISOs to facilitate long-term contracts by providing a web-based platform for contracting, but objects to mandatory reporting requirements. LPPC strongly encourages the Commission to address means for mitigating marginal loss charges that create transmission price volatility detrimental to long-term contracting practices.

- **Market Monitoring:** LPPC supports measures to enhance Market Monitor Unit (“MMU”) independence, both from market participants and from the RTOs and ISOs whose markets they monitor. LPPC asks the Commission to broaden the reach of its proposal requiring MMUs to share market analysis with state commissions in order to embrace state attorneys general and stakeholders-- groups with an avid interest in the operation of the markets and the capability of bringing dysfunction to the attention of the MMUs and the Commission.

- **RTO/ISO Responsiveness:** The Commission’s focus on developing approaches which will enhance RTO and ISO responsiveness to their customers, and means for ensuring cost-effective operations, is critical. The proposed rule in this case should include requirements for: (1) publication of meaningful, detailed strategic plans; (2) periodic measures of customer satisfaction; (3) performance criteria for RTO and ISO executives tied to specific objectives, including the ability to meet budgets. Further, stakeholders must be permitted to review, and the Commission must pass on, budgets prospectively. Most important, LPPC believes that all substantial RTO and ISO capital expenditures and all significant tariff changes must be supported with cost-benefit analyses.

II. COMMENTS

A. Demand Response and Pricing During Power Shortages in Organized Markets (ANOPR at PP 34 -82)

LPPC supports the Commission’s effort to facilitate the conduct of demand response programs in RTO/ISO markets, and certainly the Commission’s aim of ensuring that wholesale markets are “designed to accommodate demand resources in a manner comparable to supply

resources, unless prohibited by state law.”⁵ LPPC is encouraged by the potential for effective demand response programs to reduce prices and volatility in organized markets.⁶

The Commission is right in recognizing that demand response programs involve state-jurisdictional retail rate issues intimately. As the Commission observes: “[a]n effective way for demand to respond to price is at the retail level, through some form of time-based retail rates (time-based retail rates that vary by hour, such as real-time pricing, or by blocks of time, such as time-of-use rates or critical peak pricing).”⁷ Consistent with that observation, LPPC members outside and within RTOs have been actively involved in the promotion of DSM programs nationwide, both within and outside RTO/ISO-administered markets. These programs underscore the observation that demand response programs are not exclusively, or even predominately, a federal matter, but closely related to state-controlled retail policies.

1. LPPC Supports Proposals to Facilitate Bid-In Programs Where Benefits Are Demonstrated

LPPC supports efforts to advance the first three FERC proposals for the design of RTO/ISO markets in order to facilitate the operation of demand resources, *viz.*: (a) an RTO/ISO obligation to purchase demand resources in markets for ancillary services; (b) modification of RTO/ISO tariffs to eliminate deviation charges; and (c) a requirement for RTOs/ISOs to amend market rules to permit retail aggregation to bid demand reduction.⁸ However, with respect to these proposals, LPPC urges the Commission to permit RTOs and stakeholders to consider each region’s circumstance before a blanket requirement is imposed. With respect to ancillary

⁵ ANOPR at P 35.

⁶ See ANOPR at PP 36 – 38, *citing* Smith and Kiesling, *Market-Based Model for ISO-Sponsored Demand Response Programs* (September 2005).

⁷ ANOPR at P 48.

⁸ ANOPR at PP 59- 74

services particularly, it must be clear that that demand resources are capable of serving as an effective, reliable substitute for supply.

In each of these cases, in answer to the Commission's question,⁹ LPPC cautions that the Commission must ensure that the additional expenditures on demand side resources are justified by reductions in the demonstrated cost of power for all customers. As the Commission notes, the theoretical potential for such cost reduction lies in the effect on the market price of reducing marginal demand during peak periods. In order for these programs to be cost-justified, it must be demonstrated that reductions to total customer charges resulting from payments to demand response resources outweighs the expenditure on these resources. Recognizing the difficulty of predicting whether demand response initiatives will be productive, cost-benefit support may be provided either through pilot programs or after-the-factor monitoring and substantiation of benefits.

2. LPPC is Opposed to Proposals to Relax Market Power Mitigation Rules in the Name of Encouraging Demand Response

LPPC is fundamentally opposed to proposed modifications to RTO/ISO market power mitigation rules as a means of encouraging demand response. No matter how couched, each of the four alternatives posed by the Commission at PP 75 – 84 amount to the same thing: the relinquishment of regulatory control and an unjustified transfer of wealth from customers to the generation sector, with scant evidence that it will accomplish the goal of reducing costs to consumers. Abandoning price caps during periods when the market is most vulnerable to the exercise of market power would violate one of the fundamental precepts underlying market-based rates – that the Commission may rely on market-based rates only if it ensures that competitive markets function to drive rates into the zone of reasonableness.

⁹ ANOPR at P 82.

The starting point for LPPC’s thinking on this issue lies in the rationale for the imposition of market mitigation measures to begin with. As the Commission noted when extending price caps in the New England ISO (“ISO-NE”), price caps are designed to prevent “opportunistic pricing” during periods of capacity shortage.¹⁰ According to the Commission: “[T]he bid cap provides a safety net to contain prices in peak periods when supply is short.”¹¹ Equally to the point, in an earlier order extending price caps in operating capability and reserve markets, the Commission reasoned that removing the caps would “expose New England ratepayers to having to pay the arbitrarily high and unreasonable prices that suppliers could demand during periods of capacity deficiency or emergency without any offsetting benefit.”¹² The Commission has long-approved the use of price caps in other RTO/ISO markets such as in PJM, the New York ISO, CAISO and the Midwest ISO.¹³ As the Commission commented in *New York Indep. System Operator, Inc., et al.*, “if the load cannot respond to increases in prices, then generators can submit very high bids that NYISO must accept when supply is tight during peak periods, and price spikes can be magnified.”¹⁴

The Commission’s recognition that customers must be protected from the exercise of market power when demand exceeds supply is echoed in the “pivotal supplier” analysis that serves as one of two threshold tests for determining whether suppliers will be permitted to charge market-based rates. The Commission’s reliance on this test was recently reiterated in the final rule promulgated by Order No. 697. There, the Commission describes the test as asking

¹⁰ *ISO New England Inc.* 97 FERC ¶ 61,090, at 61,469 (2001).

¹¹ *Id.* at 61,470-471.

¹² *ISO New England, Inc.*, 90 FERC ¶ 61,170 at 61,554 (2000).

¹³ *Midwest Indep. Transmission Sys. Operator, Inc.* 108 FERC ¶ 61,163, PP 380-81 (2004); *California Indep. Sys. Operator Corp.*, 100 FERC ¶ 61,060, P 47 (2002); *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 (2002).

¹⁴ 97 FERC ¶ 61,154, 61,673 (2001).

“whether the market demand can be met absent the seller during peak times.” Putting it another way, the Commission comments that “a seller is pivotal [and market-based rates therefore proscribed] if demand cannot be met without some contribution by the seller or its affiliates.”¹⁵

The logic behind this test lies in the Commission’s determination that market power lies in a supplier’s ability to cause a shortage by withholding capacity. It stands to reason, *a fortiori*, that in a shortage – when all suppliers are capable of affecting price by withholding capacity (i.e., when all suppliers are pivotal) – the Commission has an obligation to maintain just and reasonable rates through some form of price control. The Commission’s proposal in the ANOPR to release price controls at precisely these critical periods cannot be reconciled with this precedent and undermines the Commission’s core mission to ensure just and reasonable rates.

With respect specifically to the argument that demand side measures may serve as an antidote to higher market prices in the absence of mitigation, the Commission has previously been circumspect, in view of the lack of evidence that necessary metering for retail customers exists, and that demand would be sufficiently responsive to provide a net cost-benefit. As the Commission previously put it:

...demand is largely unresponsive to the hourly price in the ISO’s markets. Thus, the bids of generators are not constrained by the amounts that buyers are willing to pay- even if retail customers would not be willing to pay the generators’ prices. The lack of demand responsiveness is due, at least in part, to factors that prevent retail customers from seeing the hourly spot market energy price, rather than due to any inherent willingness of retail customers to buy electricity at any price. These factors include a lack of meters to measure the customer’s energy consumption by hour, and retail rate designs that establish prices that are fixed over long periods.¹⁶

¹⁵ *Market Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295 at P 36 (2007).

¹⁶ *NSTAR Service Co. v. New England Power Pool*, 92 FERC ¶ 61,065 at 61,199 (2000).

Similarly, in *New York Indep. System Operator, Inc., et al.*, the Commission imposed a bid cap based on its finding that the “lack of demand-side responsiveness to price and the tight supplies would exacerbate the potential problems for NYISO.”¹⁷

In a partial dissent accompanying the ANOPR, Commissioner Kelly has made precisely this point, citing Staff’s Demand Response Assessment, issued August 8, 2006. As Commissioner Kelly commented:

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.¹⁸

Echoing the Commission’s own prior decisions, Commissioner Kelly’s dissent highlights that the state of play is such that permitting market prices to rise to market-clearing levels in situations of scarcity will do no more than provide a transfer of wealth to generators positioned to supply power in those instances, with no demonstrable impact on demand. LPPC is quite convinced that by doing so, the Commission would risk violating its statutory responsibility to establish just and reasonable rates. Precedent is clear that market-based rates may be relied on

¹⁷ *Id.* at 61,672.

¹⁸ Partial Dissent of Commissioner Suedeen Kelly at p. 2. Staff’s 2007 DSM report issued September 2007 indicates that there is only limited progress in metering placement.

only where the Commission has determined that the market is sufficiently competitive to bring rates into the zone of reasonableness. *See, e.g., California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004), *cert denied*, (U.S. 2007); *Interstate Natural Gas Ass’n v. FERC*, 285 F.3d 18, 30-31 (D.C. Cir. 2002); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866 (D.C. Cir. 1993); *Louisiana Energy & Power Auth. v. FERC*, 141 F.3d 364, 369-71 (D.C. Cir. 1998). Abandoning price caps at the very time the Commission has already determined they are needed in order to restrain prices in times of scarcity risks a finding of “regulatory abdication.” *Lockyer*, 383 F.3d at 1014-15; *Public Utility District No. 1 of Snohomish County v. FERC*, 471 F. 3d 1053, 1084-85 (9th Cir. 2006), *pet. for cert. pending*. (“*Snohomish*”).

LPPC adds that such action may as well have the unintended consequence of destabilizing long-term agreements, in the wake of *Snohomish*. In *Snohomish*, the court reversed FERC for failing to consider revisions to long-term electric supply agreements entered into at a time of marked market turmoil. While the court held that long-term market-based rate contracts may be protected under the *Mobile-Sierra* doctrine, the court declined to extend such protection where the Commission failed to exercise ongoing oversight of the market as of the time of contract formation. A Commission decision to relinquish market mitigation, and thereby allow prices to rise to market-clearing levels during times of shortage, would open long-term contracts entered into during such times to attack on grounds similar to those articulated in *Snohomish*.

B. Long-Term Power Contracting in Organized Markets (ANOPR at PP 92-97)

LPPC appreciates the Commission’s interest in developing additional suggestions for means by which long-term power contracting may be facilitated, and supports certain of the tentative proposals below. As the Commission is painfully aware, price volatility has been a critical failing for organized markets. The promotion of longer-term contracting practices serves

both as a direct hedge against price volatility for the contracting parties, and an effective check on the spot market itself, in the same way as does ownership of hard assets.

In addition to the specific suggestions advanced by the Commission, LPPC strongly encourages the Commission to take a fresh look at the adverse affect that transmission charge volatility has and will continue to have on the market for long-term power supplies. As was noted in the course of the technical conferences preceding the ANOPR, transmission cost volatility is a substantial obstacle to the development of long-term supply contracts and resources,¹⁹ and is an area in which the Commission possesses ample authority, notwithstanding the Commission's general comment that it has only limited jurisdiction over matters related to long-term contracting opportunities.²⁰ Specifically, LPPC asks the Commission to explore means by which charges for marginal losses associated with operation of the LMP market may be hedged or mitigated, and whether alternative pricing and loss methodologies are needed to mitigate this volatility, and chilling effect it has on long-term contracting.

1. LPPC Is Opposed to a Mandatory Reporting Requirement for Bilateral Agreements

LPPC does not believe that a reporting requirement applicable to customers would be advisable. In bilateral markets which are not entirely liquid (as is the case for the market for long-term agreements), there is reason to believe that the mandatory posting of data may harm, rather than enhance, consumer welfare. In a market-based rate environment, of course, suppliers' costs are not always known. A suppliers' knowledge, however, of prices for all equivalent deals may very well establish a floor on supplier bids when entering negotiations, serving to advantage suppliers rather than consumers. While a fully liquid market enhances the

¹⁹ See Comments of Jan Schori filed on behalf of LPPC in AD07-7-000.

²⁰ ANOPR at P 92

probability that suppliers will bid against one another for opportunities, a less liquid market, particularly one in which customer demand for long-term products may outstrip supply, is likelier to exhibit price-following behavior. LPPC cautions the Commission against a format which may encourage this result.

2. LPPC Encourages the Commission to Foster Long-Term Supply Arrangements Through the Elimination of Charges for Marginal Losses

LPPC asks the Commission to permit the parties to the forthcoming NOPR to explore mechanisms by which charges for marginal losses may be mitigated, or alternative pricing strategies employed, in order to remove a disincentive to the operation of the market for long-term power. LPPC's strong preference is for a rate alternative that results in more stable prices to begin with, rather than volatile charges that must be hedged.

LPPC recognizes that in Docket No. RM06-8-000, the Commission rejected the argument that EAct 2005 section 1233 (new section 217 of the Federal Power Act) required the elimination of charges for marginal losses, or full hedges.²¹ Yet, the Commission has been clear that its decision “does not preclude future market design changes that allow hedging of losses.”²² Further, the Commission stated expressly that “we encourage transmission organizations to explore methods by which they can assist load serving entities and others to obtain a hedge for marginal losses.” With that in mind, LPPC urges the Commission to use this docket as a vehicle for exploring means by which the impact of marginal loss charges may be hedged or otherwise mitigated.

²¹ See *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 71 Fed. Reg. 43,564 (August 1, 2006), FERC Stats. & Regs. ¶ 31,226 at P 477, *order on reh'g*, Order No. 681-A, 117 FERC ¶ 61,201 at PP105-106. (2006).

²² Order No. 681-A at P 106.

The potential impact of the imposition of marginal losses on the price of delivered power is enormous and unpredictable. LPPC is aware that the Commission has approved marginal loss charges in various markets.²³ Yet, LPPC is convinced that the destructive impact of these charges on the market for long-term bilateral supply has been inadequately appreciated. Establishing a predictable price for supply is the reason for parties to enter into long-term supply contracts to begin with. In choosing among supply alternatives, the cost of transmission is a significant factor, obviously weighing considerably on the overall cost of delivered power. The volatility associated with congestion pricing and unpredictable marginal loss charges makes these decisions more difficult not only for customers, but for suppliers uncertain how to price their product. The effect of this uncertainty is to dampen both supply and demand for long-term contracts. The resulting dependence on short-term markets, with attendant supply price volatility and periodic shortages, has been a persistent problem for the industry. A comprehensive solution is needed, and LPPC asks the Commission to remain open to the view that hedging mechanisms (a costly alternative) may be a poor second-best to pricing methodologies that ensure more certain transmission pricing to begin with.

In a variety of settings, the Commission has expressly recognized the adverse impact that volatile congestion charges have on supply markets and end use customers. Dramatically fluctuating transmission costs make it impossible to properly evaluate supply options for which the delivered price is uncertain.²⁴ Conceptually, charges for fluctuating marginal losses are no

²³ See *California Indep. Sys. Operator*, 120 FERC ¶ 61,023 (2007); *Midwest Indep. Trans. Sys. Operator, Inc.*, 102 FERC ¶ 61,196 at P 53 (*MISO*), *order on reh'g*, 103 FERC ¶ 61,210, at P 28-29 (2003); *Central Hudson Gas & Elec. Corp.*, 86 FERC ¶ 61,062 (*Central Hudson*), *order on reh'g*, 88 FERC ¶ 61,138, at 61,384-85 (1999); *New England Power Pool*, 100 FERC ¶ 61,287 (*NEPOOL*), *order on reh'g*, 101 FERC ¶ 61,344 (2002); *Northeast Util. Serv. Co.*, 105 FERC ¶ 61,122, at P 18-20 (2003) (*Northeast Utils.*), *reh'g denied*, 109 FERC ¶ 61,204 (2004); *Atlantic City Elec. Co. v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132 at P 4 (2006).

²⁴ See Order No. 681 at PP 10, 16 (“The guidelines we adopt in this Final Rule are designed and intended primarily to ensure that the long-term firm transmission rights that are made available by transmission organizations that are subject to the rule have characteristics that will support a long-term power supply arrangement.”)

different. The adverse impact of the imposition of these charges on long-term planning and the market for long-term supply is potentially equal to the impact of unhedged congestion charges. The Commission has recognized as much, commenting in Order No. 681-A that “[m]arginal losses are similar to congestion costs in that they are a function of locational energy prices and line loadings.”²⁵ Nevertheless, in Order Nos. 681 and 681-A, the Commission declined to require the implementation of hedging or mitigation for marginal losses in view of the Commission’s determination that “we do not interpret section 217(b)(4) as addressing marginal loss charges,” and its conclusion that “the development of a financial instrument or other means of hedging of marginal losses has not been accomplished to date in any of the organized electricity markets.”²⁶

Whether effective mechanisms can be developed to hedge marginal loss charges remains to be seen. The need for mitigation, however, has been already been established. With that imperative as a given, LPPC believes the Commission should move forward by requiring RTOs/ISOs to present a menu of options for evaluation in this proceeding. As well, LPPC believes the Commission should be receptive to other means of mitigating these charges. While LPPC recognizes that the Commission has commented that marginal loss charges may be useful in sending appropriate price signals,²⁷ the Commission should be receptive to arguments for effective ways to balance such price signals while avoiding the most dramatic impact on the supply market.

C. Market Monitoring

LPPC is encouraged by the reforms suggested by the Commission and certainly supports efforts to enhance the independence of market monitors from market participants, as well as

²⁵ Order No. 681-A at P 105.

²⁶ *Id.*

²⁷ See *California Indep. Sys. Operator*, 120 FERC ¶ 61,023 at P 247 (2007);

from the RTO or ISO whose markets they monitor. LPPC supports APPA's more extensive comments on these points. Clearly, there is room for improvement in this area.

LPPC pauses here to comment specifically on the Commission's proposal to require MMUs to share information developed in their analysis of wholesale market conditions and flaws than is currently the practice. At P 122 of the ANOPR, the Commission comments that it "favors both a fuller sharing of information and identification of the relevant information desired, so that the needs of the Commission, the state commissions, market participants and the public may be satisfied." LPPC is squarely behind this approach.

However, at PP 123 – 125 of the ANOPR, the Commission goes on to describe at some length the interest of state commissions in securing market analysis and data, and in being briefed by the MMUs on the state of the markets, apparently to the exclusion of other market participants. If this omission is not simply inadvertent, LPPC asks the Commission to reconsider. Market participants have an avid interest in ensuring that the markets function appropriately, and the broader the understanding of the MMUs' analyses and the data from which the MMUs perform their analyses, the better able market participants will be in bringing issues to the MMUs' and the Commission's attention. Before MMUs were created, the Commission relied almost exclusively on reports from market participants regarding market dysfunction and abuse. In this context, similar to the manner in which private parties may bring antitrust violations to judicial light, market participants function essentially as private attorneys general. The Commission should have every interest in encouraging this activity. For the same reasons, the Commission should require market information to be shared with interested state attorneys general, who have in many cases been among the most successful and effective prosecutors of antitrust and consumer protection violations.

D. Responsiveness of RTOs and ISOs (ANOPR at PP 134 – 163)

LPPC believes the Commission is right to direct its attention to RTO and ISO responsiveness, and particularly to measures related to the matter of management incentives and costs. In LPPC members' experience, there is vast room for improvement with respect to RTO/ISO managements' receptivity to stakeholder input, management practices that bear on the effectiveness of RTO/ISO policies and operations, and the cost of RTO operations, including costs directly incurred by RTOs/ISOs and those imposed indirectly on market participants as a result of RTO/ISO policies. The Commission is absolutely right that its fundamental goal must be to build a culture of "customer responsiveness" and "customer orientation," beginning with RTO/ISO boards of directors.²⁸

Accordingly, LPPC embraces the Commission's preliminary determination to require each RTO or ISO to develop a means for ensuring that stakeholder representatives have direct access to RTO/ISO boards of directors.²⁹ LPPC further endorses each of the Commission's specific proposals for improving RTO/ISO management practices.³⁰ In addition, LPPC agrees with the Commission that RTO/ISO budgeting processes must be more transparent, although it believes the Commission must go further in order specifically to approve budgets in advance, and to ensure performance within those budgets.

Missing from the Commission's laundry list of improvements, however, is the touchstone by which all RTO and ISO activities must ultimately be evaluated: cost-benefit analysis. As argued below, the Commission must require RTOs and ISOs either to justify, in advance, all

²⁸ ANOPR at P 147.

²⁹ ANOPR at P 148.

³⁰ ANOPR at P 159.

significant capital expenditures and all significant tariff changes on the basis of cost-benefit analysis, or explain why this cannot be done.

1. RTO/ISO Responsiveness to Stakeholders

LPPC agrees with the Commission that a direct relationship between RTO/ISO boards of directors and stakeholder representatives is potentially a very useful means of bridging the gap between stakeholder concerns and RTO management. While LPPC takes no position on the proposal for “hybrid boards,” there is strong support among LPPC members for direct representation of stakeholders through what the Commission describes (ANOPR P 153) as a committee of senior executives of stakeholder groups serving to advise the RTO Board on stakeholder interests. To ensure effective and faithful representation of the stakeholder community, LPPC recommends the following broad guidelines in the constitution and operation of such a committee (here dubbed a “Senior Stakeholder Advisory Committee,” or “SSAC”):

- The SSAC must be closely involved in RTO/ISO board discussions prior to the time key decisions are made. Although these representatives would not have voting authority, LPPC expects that they should be present and participate in discussions when significant reports are made by management and decisions debated.
- The SSAC must faithfully represent a broader range of stakeholder interests. The best insurance that this obligation will be honored will be to institutionalize a careful and fair process for selecting these individuals, while instituting a process by which they are answerable to the broader stakeholder community and charged with gathering stakeholder input and recommendations.
- The SSAC should supplement, not replace, existing stakeholder representation on operating technical committees.

2. RTO and ISO Executive Management Practices (ANOPR at PP 157-59)

LPPC strongly encourages the Commission to follow through with the proposals advanced at P 159 for institutionalizing procedures designed to ensure greater management accountability to stakeholders. On the merits of these proposals, LPPC offers the following:

- **Publication of Strategic Plan:** The publication of RTO/ISO strategic plans is a critical step in fostering accountability. In order to be a meaningful exercise, the publication should, first, be an annual event, which precedes board approval with sufficient time to permit meaningful debate and input. Second, the plan must provide a substantive roadmap for all substantial RTO/ISO activities to be undertaken over the ensuing year and beyond. This would include a discussion of all significant expenditures on projects of strategic significance to stakeholders, and a discussion of all substantial tariff-related changes that the RTO/ISO plans to undertake.
- **Measures of Customer Satisfaction:** LPPC fully supports a requirement for RTOs/ISOs to undertake a periodic (perhaps biannual) measure of customer satisfaction, akin in purpose and scope to surveys undertaken by utilities at the state level. Key elements should reflect each area of an RTO/ISO's responsibility, including, among other things, the organization's effectiveness in the following areas: (1) processing applications for service, (2) regional planning; and (3) reliability.
- **Performance Criteria and Executive Compensation:** LPPC sees the establishment of objective criteria for performance, and a nexus between such performance and executive compensation, to be critical elements in the contemplated reforms. The imperative for such measures follows from the fact that RTOs and ISOs cannot respond as institutions to financial incentives and cost disallowances as would investor owned utilities, since they have no

shareholder equity to draw upon. All costs, whether prudently incurred or not, are ultimately borne by ratepayers. Nor are these organizations politically accountable. Accordingly, to ensure management's responsiveness, LPPC strongly urges the Commission to require RTOs and ISOs to develop performance criteria and compensation proposals aimed at providing management a substantial incentive to meet identified goals. The four broad bases that these proposals should cover in these proposals include: (1) accomplishment of the mission articulated in RTO/ISO strategic plans; (2) the ability to meet budget projections (discussed below); (3) the ability to comply with NERC Standards, and (4) the ability to meet measures of stakeholder satisfaction, as measured in stakeholder surveys.

3. Transparent RTO and ISO Budgeting Practices (ANOPR at PP 162-163)

The Commission correctly identifies RTO/ISO budgeting and expenditures as a key concern for the industry. As the Commission has recognized (ANOPR at P 162, n.123), RTO's and ISOs simply cannot be regulated as would investor owned utilities, since the Commission has no ability to disallow cost recovery. Accordingly, prospective consideration of an RTOs budget is critical. With respect to stakeholder review of this material, LPPC believes the measures outlined by the Commission at P 163 are good ones, and should be mandated. LPPC agrees that customers must be presented with budgets prospectively, and that RTO/ISO management must be required to consider stakeholder input on proposed expenditures.

Having said this, there are two important components that the Commission appears to have left out of this process. First, LPPC believes that in RTOs/ISOs where stakeholders so request, budgets must be presented to the Commission not only for informational purposes, but for approval. While the Commission appears to contemplate only an "informational filing," that concept would appear to establish the basis only for an after-the-fact review that the Commission

has itself acknowledged has little value.³¹ In RTOs/ISOs where stakeholder communications work well, there may be no need for the Commission to take further steps. LPPC members have found that certain stakeholder committee structures work reasonably well in ensuring that stakeholders have appropriate input into budget matters, and the Commission may find that in that context, stakeholders may not insist that budgets be filed. However, upon the request of a majority of stakeholders, advanced Commission review of an RTO's budget would be appropriate.

Second, in order for an approved budget to have meaning, and not simply to serve as a guideline that may be ignored, the Commission should insist on a mechanism for tying executive compensation to the ability to meet the budget. The nature of such these programs should be developed in stakeholder processes within each RTO/ISO. As a practical matter, this is what occurs in the investor-owned utility world, when utility managers cannot provide service within the established rates. To be sure, these mechanisms must be sufficiently flexible to accommodate cost fluctuations not reasonably within management's control. Yet, only with some such nexus to financial performance can the Commission be assured that management will take its budgets to heart.

4. Cost-Benefit Analysis is Essential to the Approval of Significant Capital Expenditures and Major Tariff Changes.

At bottom, much of the discontent expressed over RTO/ISO performance is rooted in the concern that these organizations have not accomplished their objectives in a cost-effective manner. It stands to reason, accordingly, that an effective response by the Commission will involve an effort to reintegrate RTO/ISO objectives and costs. To that end, LPPC firmly

³¹ For investor-owned utilities with formulaic rates, informational filings establish the basis for prudence challenges which may be brought retrospectively on the ground that charges are inconsistent with the formula. That process cannot be used to protect customers of an entity whose costs simply cannot be disallowed retrospectively.

believes that cost-benefit analysis should be a routine part of RTO/ISO decision-making. The key areas that stand to benefit from such analyses are decisions related to substantial capital budget items and significant tariff changes. These two elements may overlap, as would be the case, e.g., for tariff changes and computer system expenditures related to the implementation of the California ISO's MRTU tariff, and the Midwest ISO's Day-2 market. The costs and benefits considered in such analyses should be internal and external. Internal costs will include direct expenditures by the RTO or ISO, while internal benefits may include efficiencies in the performance of existing functions. External costs will include the estimated cost of compliance by market participants related to new tariff provisions, and external benefits will reflect efficiencies and cost savings in the markets.

To implement this proposal, with respect to substantial capital budget items, LPPC recommends that, where a majority of stakeholders so request, cost-benefit analyses be submitted with annual budgets for approval by the Commission. LPPC expects that such analyses will be the subject of substantial stakeholder input prior to the time budgets are filed, and the degree of necessary Commission scrutiny will undoubtedly be a function of the level of stakeholder support for the RTO/ISO proposal. Because this stakeholder process works reasonably well in certain RTOs, LPPC recommends that the further step of filing cost-benefit analyses with FERC be taken following support for that concept among a majority of stakeholders.

With respect to significant tariff changes, cost-benefit analyses should be submitted with the RTO/ISO section 205 filings, again following what LPPC would expect to have been substantial stakeholder input. Where RTOs and ISOs are convinced that a particular tariff change does not lend itself to a cost-benefit analysis, it should explain why. Here again, because stakeholder approval for tariff changes is already sought in certain RTOs/ISOs, LPPC

recommends that the cost-benefit requirement be implemented upon request by a majority of stakeholders.

While LPPC certainly expects resistance to the level of incremental work that the conduct of formal cost-benefit analyses will require, the necessity of the exercise seems indisputable. Indeed, there is no other way to measure the success or failure of what an RTO or ISO does than to ask whether the benefits outweigh the costs. The Commission itself has acknowledged an obligation to consider cost-benefit analysis, when it is presented by intervenors,³² and all LPPC asks here is the Commission's recognition that its experience with RTOs/ISOs over the past decade calls for RTOs/ISOs to present such analyses themselves. LPPC adds that this way of thinking should be implicit, if it is not already explicit, in all RTO/ISO decision-making. The discipline of having to explain decisions in this manner to stakeholders and the Commission should be most useful ultimately in reducing the level of friction between RTO/ISOs and their customers and developing consensus around RTO/ISO plans.

³² *Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

CONCLUSION

For the reasons articulated above, LPPC urges the Commission to proceed with a Notice of Proposed Rulemaking consistent with the foregoing comments.

Respectfully Submitted,

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