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ELECTRICITY LAW DEVELOPMENTS – May 6, 2008

Prepared for ELCON

This report summarizes recent developments in FERC proceedings in which ELCON has been active and other matters of interest to industrial consumers. Inside this issue:

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New developments since the April 2008 issue of Electricity Law Developments are in bold.

I. FERC PROCEEDINGS

A. Reforms to the Organized Markets (FERC Docket Nos. RM07-19, AD07-7)

On February 22, 2008, the FERC issued a notice of proposed rulemaking intended to improve wholesale organized (RTO and ISO) electric ity markets. The proposed rule continues a proceeding that began in 2007 with two technical conferences and an advance notice of proposed rulemaking.

The proposed rule has four major components: (1) demand response and market pricing during periods of reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) responsiveness to stakeholders and customers. Most of the requirements would be implemented through revisions to the tariffs of RTOs and ISOs due six months after a final rule, and therefore would be the subject of a series of future proceedings.

ELCON's Comments

In their September 14, 2007 comments on the ANOPR in these dockets, ELCON, together with the American Chemistry Council (ACC) and American Iron and Steel Institute (AISI) ("ELCON") urged the Commission to use the proceeding to begin a process by which the current mix of regulation and competition in the organized markets is reconsidered to ensure that customers receive the benefits they deserve from restructured markets. ELCON was encouraged by the ANOPR because it acknowledged several critically important areas for reform in the organized markets that ELCON had identified numerous times over previous years as essential pre-conditions to real, effective wholesale competition. These included: (1) an expanded role for demand response and the elimination of barriers to the integration of demand response in price formation, (2) the recognition that it is important

that wholesale buyers and sellers have adequate opportunities to sell and buy power (and hedge spot price volatility) through long-term power contracts, (3) reforms to the market monitoring function of ISOs and RTOs to ensure independence, and (4) reforms to ISO/RTO governance to increase the responsiveness of ISOs and RTOs to stakeholders and customers. According to ELCON, the Day-Two market structure that mixes regulatory mechanisms with bid-based auctions has not resulted in a true competitive market, a situation that has been further compounded by growing hostility to consumer interests within ISO/RTO stakeholder processes and questions regarding the objectivity and independence of market monitoring units.

The NOPR, however, was disappointing and if implemented is likely to result in increased electricity prices and profits of utility holding companies and those investing in utilities. ELCON asserts that the NOPR not only backtracks from the ANOPR, but also the Commission appears to have abrogated its own role in rulemaking and punted it to six ISO/RTO stakeholder processes. Instead of forthright and consistent directives, such as a pro forma tariff, to command the necessary market reforms, consumers must participate in separate and costly stakeholder processes at each ISO and RTO with the inevitable outcome of a series of six disparate compliance filings that are further adjudicated before the Commission. Furthermore, without the assurance that any essential pre-conditions to competition are achieved, the NOPR directs each ISO and RTO to implement scarcity pricing.

Among ELCON's specific comments are the following:

Demand Response

ELCON recommends that the final rule incorporate a *pro forma* demand response tariff (“DR tariff”), analogous to the *pro forma* tariff language requiring open access to transmission. ELCON notes that focus on economic arguments supporting demand response has not attracted the votes necessary for bold Commission action on this issue to date, notwithstanding the strong advocacy for economically-driven demand response contained in reports to Congress written by the Commission's own staff. The *pro forma* DR tariff proposal is a different tactic and is intended to make the case that a *pro forma* DR tariff based on best practices is a good idea as a matter of law and will help reduce discrimination in the electricity markets. It has been FERC’s long-standing practice to specify particular *pro forma* tariff language to implement significant reforms in the electricity markets, particularly where necessary to promote consistency and avoid undue discrimination. In the instant proceeding, if FERC allows each organized market to devise its own tariff language or demand response policy, the result is likely to be delay and inconsistency across the markets.

ELCON also urges that demand response compensation be resolved quickly. Potential providers of demand resources will not step forward if compensation is not provided and guaranteed on a comparable basis to that provided to generators.

ELCON is concerned that the scarcity pricing proposal is premature given that the pre-conditions necessary to safeguard consumers are absent. If the final rule retains this requirement, ELCON urges FERC to allow price levels to increase only in tandem with and proportional to the demonstration that certain benchmarks have been met.

Market-Monitoring Policies

ELCON generally supports the proposed rule changes that safeguard market monitoring units' independence and increase transparency. However, ELCON advocates a "hybrid" market monitoring unit structure, which provides the unique feature that top tier members would be financially independent from the ISO or RTO.

Responsiveness of ISOs and RTOs

The NOPR proposes to establish four new principles intended to ensure that an ISO or RTO is responsive to its customers and requires each ISO and RTO to make a compliance filing detailing how the entity's existing practices comply with each principle or its plans to attain compliance. ELCON supports increased RTO and ISO accountability through hybrid boards comprised of a minority of stakeholder members who would represent an even split between consumer and supplier interests.

Other Comments

Approximately 85 parties filed comments. Although many of the comments reprised arguments already submitted in response to the ANOPR, there were a few new or expanded points perhaps triggered by the Commission's emphatic request for specific proposals.

Scarcity Pricing

A number of commenters supported demand curves or analogous approaches.

- *Constellation Energy Commodities Group* advocated use of demand curves to set prices for reserves while noting that "[c]alibrating the parameters of the reserves demand curve . . . continues to leave some questions unanswered." Constellation referenced the use of demand curves or reserve constraint penalty factors in NY-ISO and ISO-NE and supported gradual transition to demand curves for all hours as a better alternative to abrupt triggering of scarcity pricing upon an RTO-declared emergency.

- *Potomac Economics* also favored demand curves for operating reserves, complemented with systems of efficient shortage pricing for emergency demand response, emergency transactions, export curtailments, voltage reductions and other emergency actions.
- *PPL affiliates* supported demand curves as the best solution, with the next-best approach the removal of price caps during shortages: “The demerits of such caps have consistently been recognized by the Commission and its staff, even as the caps were temporarily implemented. It is unfortunate that they have become a design feature of many markets for so long.”
- *Exelon* supported staged increases in bid caps as a reserve shortage develops.

Other commenters emphasized that the prerequisite of competitive market conditions is not yet in place.

- The *New Jersey Board of Public Utilities* stated that scarcity pricing “will not produce the Commission’s desired result if the customers cannot or do not react.” Because so many customers pay fixed retail rates, “a major increase in wholesale electricity prices during peak hours cannot be expected to attract new demand resources from the large majority of New Jersey customers.”
- In opposing the proposal to remove price caps during periods of scarcity, the *Pennsylvania Public Utilities Commission* observed that FERC appeared to have two misconceptions – that a competitive market would otherwise exist if the caps were removed and that load interests are slow in adopting demand response; instead, “[w]hat is more likely is that generation will obtain the freedom to bid what it chooses, while simultaneously delaying or blocking the legal and physical infrastructure necessary for such demand response to develop.”
- *Alcoa* noted that the scarcity pricing proposal is premature in the absence of a showing that markets are competitive and that incremental benefits “may fall short of compensating for the overall increase in electricity prices that might occur as price caps are removed.”
- The *Steel Manufacturers Association* commented that “the fundamental elements required to permit the lifting of market price caps during scarcity periods simply are not in place today.”
- Opposing the scarcity pricing proposals including an administratively determined demand curve, *APPA* submitted a paper by James Wilson expressing the view that PJM’s Interconnection Reliability Pricing Model is not working properly and overstates the need for new capacity.

- *FTC* noted that the “absence of dynamic retail pricing or other mechanisms to moderate demand during periods of scarcity is one of the most serious flaws in organized electricity markets. The Commission noted that the other restrictions on wholesale pricing that could remain in force “could bind so tightly that they would mute the more timely and efficient price signals to consumers and generators provided by lifting the wholesale rate caps.” To address this issue, FERC should consider expanding the periods in which rate caps would be relaxed and base such expansions in part on the extent of participation in demand response.
- *The Transmission Access Policy Group (“TAPS”)* commented that the required “empirical proof” of competition requires the Commission to strengthen the factual showing that RTOs must make in support of scarcity pricing proposals. Such showing should include: (1) specific competitive analysis of market power risks during scarcity conditions and whether demand response mitigates market power; (2) review of the incentive and ability of market participants (especially those with generation) with exercise market power by withholding demand response; (3) demonstration that the RTO’s market mitigation measures effectively target market power under scarcity conditions; (4) determination that there is enough demand response to restrain prices during scarcity, taking into account its use for capacity reserves and ancillary services; and (5) statistics on scarcity conditions to ensure that they are rare.

Demand Response

Although there was general support for the concept of “comparability,” different commenters had somewhat different perspectives about how that concept should be applied in practice.

- *Alcoa* commented that “vaguely stated concepts of comparability of resources and ‘reasonable requirements’ to increase access to these services” may be ineffective. Instead, the final rule should mandate against any restrictions on the amount of participation by demand response resources and should establish a minimum 5 percent target for participation by demand response within 12 months, unless the grid operators explain why they cannot meet that goal.
- *The Steel Manufacturers Association* observed that electric arc furnaces can curtail on 10 minutes notice in commenting that such loads “are well suited to provide the ancillary services of spinning and supplemental reserves, energy imbalance, and regulation and frequency response.” Two steel companies, *Nucor* and *Steel Dynamics*, opined that RTOs should have to allow optional bidding parameters for demand response, including parameters for minimum

notice, minimum and maximum shutdown time, targeted demand reduction level, and guaranteed minimum LMP.

- *NARUC* and various individual state commissions cautioned that ISOs and RTOs must first seek the approval of state commissions before implementing demand response programs.
- *EEl* supported the concept of comparability with qualifications – demand response resources must meet certain technical requirements, not conflict with state laws or retail programs, and be consistent with “the underlying philosophy and structure of the market in the relevant RTO/ISO.”

RTO Management

Issues relating to RTO governance continued to elicit a wide range of viewpoints.

- Parties such as *NARUC*, *New England Power Generators Association* and *International Transmission Co.* opposed efforts to mandate the composition of RTO boards and advisory committees, citing a need to preserve independence. These commenters also supported as “airtight” Commissioner Kelly’s opposition to the NOPR provision to cease allowing the MMUs to perform market monitoring.
- Southern California Edison and San Diego Gas & Electric observed that Cal-ISO was functioning well as is.
- Other parties supported enhanced participation by their represented interests. For example, *Midwest Transmission Owners* sought more transmission representation (based on the costs that would be imposed on the stakeholder group), and *Nstar* sought more consumer representation.
- *American Transmission Co.* proposed four concrete steps for improved stakeholder input: (1) specified minimum time period allowing for stakeholder review of potential RTO filings; (2) formalized mechanism for communicating minority stakeholder views to the RTO board; (3) annual RTO reports on responsiveness; and (4) “feedback loop” disclosure of how stakeholder views are considered as part of the RTO’s decision-making process.
- *APPA*’s suggestions for specific responsiveness measures include: (1) mandated direct stakeholder access to RTO boards (e.g., monthly teleconferences and quarterly meetings) with no filtering by management; (2) meaningful opportunity for board presentations by minority stakeholders on RTO proposals; (3) consideration of stakeholder advisory committees and hybrid boards; (4) open RTO board meetings with published agendas; (5) elimination of self-perpetuating boards, with multiple candidates and stakeholder input on

selection of the slate; (6) “customer satisfaction” surveys; (7) cost oversight benchmarking; (8) new markets for products or services to be supported by third party cost benefit analyses or affirmative vote of all stakeholder classes; (8) explicit mission statements on cost reduction and net benefit to consumers.

- *FTC* commented that the non-profit status of RTOs and ISOs may be a source of complaints of excessive costs and lack of responsiveness. Thus, *FTC* encouraged consideration of restructuring the organizations into for-profit Transcos or at a minimum establishing strong incentives for managers to be responsive to stakeholder concerns.
- *TAPS* supported a number of specific measures including: hybrid boards; benchmarking RTO costs to other RTOs and non-RTO transmission providers; biennial independent cost-benefit analyses; cost-benefit analyses of major rules and initiatives prior to their adoption; advance stakeholder review of annual budgets; tying senior management compensation to consumer-focused performance measures; and annual public reporting and other accountability measures related to success at relieving congestion costs, responses to transmission requests, reliability and outage statistics, and whether the RTO’s planning and expansion targets are met.

Other Issues

- *APPA* took the opportunity to submit its Day One RTO proposal, notwithstanding *FERC*’s directive that the *NOPR* proceeding be limited to the discrete issues raised in its notice. *APPA* also submitted a paper by Synapse Energy Economics Inc. discussing in detail the existing barriers to long-term contracting.
- In a wide-ranging and strongly worded comment echoing the commonly held state view, the *Pennsylvania Public Utility Commission* harshly criticized the current markets:

[W]hat the public thought it was getting from its heavy investment in competitive wholesale markets was competition; what it got instead is a constantly changing extraordinarily complex market structure composed partly of ‘workably’ competitive markets, mediated by extensive minute-by-minute mitigation of chronic market power and rules gaming.

Referencing the proliferation of administrative rules, the Commission stated:

Reliance on ad hoc fixes and the convening of regional forums and technical conferences in Washington will not be adequate to achieve the comprehensive review and reform of market design that is needed. A

failure of leadership endangers not only future generation investment in wholesale generation markets, but public support for Congress's competitive market policy initiated in 1992.

B. FERC Proceeds with Technical Conferences on the Organized Markets (FERC Docket Nos. AD08-4, AD08-8)

FERC has issued its agenda for its May 7, 2008 technical conference to discuss the operation of the forward capacity markets in ISO-NE and PJM and to learn more about the proposals of the American Forest and Paper Association and the Portland Cement Association. The conference will have five panels to discuss:

- **design and early results of PJM's and ISO-NE's forward capacity markets;**
- **AF&PA's financial performance obligation proposal;**
- **Portland Cement's long-term capacity proposal; and**
- **existing and alternative capacity market designs (two panels).**

The conference will be available via webcast.

FERC also has announced a technical conference on demand response in the organized markets for May 21, 2008. This is the second such conference related to FERC's NOPR on wholesale competition in the organized markets. Among the issues to be addressed during the conference are:

- **the value of demand response in organized markets;**
- **comparable compensation of demand response in organized markets;**
- **barriers to comparable treatment of demand response that have not previously been identified;**
- **solutions to eliminate such barriers; and**
- **the need for and the ability to standardize terms, practices, rules and procedures associated with demand response.**

A detailed agenda is not yet available. Presently, FERC is soliciting nominations for speakers at the conference. A further notice with detailed information is anticipated in advance of the conference.

C. Recent FERC Activity Related to Reliability Standards

i. FERC Adopts Penalty Notice Policy for Violations of Reliability Standards (FERC Docket Nos. RM08-7, AD08-6, RM05-30)

On April 17, 2008, FERC adopted an administrative policy for review of NERC penalty notices, including establishing schedules for filing, intervention and review by the Commission. Any entity subject to a NERC notice of penalty may file an application for review with 30 days of the notice being filed with FERC. Similar to the timeline established for other FERC proceedings, interventions on the application for review must be filed within 20 days, and FERC will generally take action on an application within 60 days. FERC may also initiate review on its own motion within 30 days of a notice being filed. Though required to review every notice for which a registered entity files an application for review, FERC said it does not anticipate reviewing every uncontested notice of penalty filed by NERC. To do so would be inconsistent with the enforcement discretion of NERC and the regional entities. In uncontested cases, FERC will weigh the seriousness of the violation when deciding whether to review penalty amounts. FERC will also review notices on its own motion to ensure that penalties are applied in a reasonably consistent manner and improve compliance with reliability standards.

FERC also announced plans to revise the policy outlined in Order No. 672, issued February 3, 2006, concerning Commission review of settlements by regional entities or by NERC of alleged violations. Order 672 stated that while settlements will be made public,

settlements would neither be noticed for public comment nor subject to FERC review. FERC is changing that policy by stating that it will review penalty settlements by regional entities and NERC, to be consistent with its policy in other contexts of reviewing settlements. FERC stressed that it continues to encourage the regional entities and NERC to enter into settlements, and that it will normally allow NERC and regional entity settlements to become effective.

ii. Commissioners Seek Comment on Ability of Demand Resources to Respond to System Emergencies (FERC Docket No. RM08-7)

On April 21, 2008, FERC proposed to adopt six modified reliability standards from the ERO. In Order No. 693, issued March 16, 2007, FERC had approved 83 of the 107 proposed reliability standards proposed by NERC and had directed the ERO to develop modifications to 56 of the 83 approved standards. Five of the six proposed reliability standards subject of the NOPR relate to interchange scheduling and coordination, while one pertains to transmission loading relief procedures for the Eastern Interconnection. FERC had asked NERC to come up with procedures to mitigate interconnection reliability operating limit (“IROL”) violations, indicating that the proposed transmission-loading relief procedure was insufficient absent additional measures because it takes too long to implement. NERC’s proposed revised standard contains the required warning that the transmission-loading relief procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation and suggests that other acceptable and more effective procedures to mitigate actual IROL violations include reconfiguration, re-dispatch, or load shedding.

In a separate concurrence to the NOPR, Commissioners Kelly and Wellinghoff note that NERC’s proposed revision does not provide for demand resources as an acceptable

alternative to transmission-loading relief despite the Commission's repeated requirement that demand resources be accorded comparable treatment to generation resources. They specifically request comments on whether demand resources that are capable of responding quickly to emergencies should be among the available alternatives to the transmission-loading relief procedures for mitigating transmission line limit violations to maintain system reliability.

FERC also proposed to approve NERC's interpretation of five other specific requirements of Commission-approved reliability standards.

Comments on these proposals are due May 28, 2007.

iii. NERC Proposal to Address Reliability Gaps Accepted by Commission (FERC Docket Nos. RC07-4, RC07-6, RC07-7)

Over protests from a number of interested parties, on April 4, 2008, FERC accepted NERC's proposal for addressing potential reliability gaps even though the proposal does not specifically identify any current reliability gaps. 123 FERC ¶ 61,016.

On September 11, 2007, three power marketers (Direct Energy Services, LLC, Sempra Energy Solutions LLC and Strategic Energy L.L.C.) filed appeals with FERC of a determination by NERC that each should be registered as a load-serving entity by the regional reliability entity. On December 20, 2007, FERC reversed NERC's determination, finding that the registration of retail marketers as LSEs was not supported by the record or by NERC's registry criteria and would result in inconsistent practices among the regional entities. FERC directed NERC to submit a plan describing how it would address the possible "reliability gap" NERC asserted would result if these retail marketers were not registered.

On March 4, 2008, NERC submitted a two -step proposal to address the potential reliability gap. First, in the near term, NERC will conduct an open comment process to revise its registry criteria to define “Non-Asset Owning LSEs” as a subset of LSEs and specify the reliability standards applicable to that subset. These revisions will be considered by NERC’s Board of Trustees during its May 2008 meeting. Then, in the longer term, NERC proposes to identify changes to terms and requirements in reliability standards to address issues surrounding the accountability for loads served by retail marketers or suppliers and process them through the execution of NERC’s three-year reliability standards development plan. NERC would begin this process with a LSE and compliance workshop to identify the issues.

Protestors asserted that NERC’s proposal did not satisfy FERC’s December directive because the ERO did not point to any specific current reliability gaps. Additionally, they argued that as a result of the proposal, retail marketers will be held responsible for a host of reliability standards over the next three years even though many of those standards would not apply to an entity’s specific situation, at least until NERC NERC defines the entity’s reliability obligations. One protestor suggested that NERC was seeking to overcome a cost gap rather than a reliability gap, since the costs to fund a regional entity’s activities come chiefly from LSEs. If this is the case, the solution should be a change to the regional entity’s funding mechanism.

FERC, however, found the plan satisfactory. The substance of both the short-term and long-terms plans will be vetted through stakeholder processes, and any substantive comments on proposals will be addressed by FERC once the plans are submitted to the Commission for filing. Further, FERC found the proposal sufficiently limited in scope in

that it addresses the potential reliability gap that would result if retail power marketers are not registered as LSEs.

D. Demand Response Issues Come to Fore in ISO-NE, PJM, and MISO Proceedings

Changes to the methodologies for calculating customer baselines based on normal usage patterns, intended to ensure that curtailment is real, and other demand response issues have been at issue in proceedings brought by ISO-NE, MISO and PJM.

i. ISO-NE (Docket No. ER08-538)

In an April 4, 2008 order, FERC approved changes to ISO-NE's program that raised the bid-offer threshold for demand response payments from a fixed \$50/MWh to an indexed amount that reflects current fuel prices. FERC found that "the relatively low Minimum Offer Price (as compared to current LMPs in New England) is the driver of static Customer Baselines and thus allows participants to receive payments for these daily phantom load reductions." Thus, "ISO-NE's proposal properly returns the DALRP to its initial purpose – namely, to provide benefit to the system at times of high LMPs – while protecting customers from being charged for services that are not in fact provided."

Commissioner Wellinghoff dissented in part on the basis that ISO-NE did not provide enough information to quantify the problem and did not fully resolve the customer baseline issue. He stated:

[I]t is important to recognize that ISO-NE's proposal leaves unresolved the fundamental problem as to how an individual customer's baseline load should be determined if seasonal variations and operations schedule changes occur. Further, raising the minimum offer price affects all demand response providers including those who have no such variations and for whom the non-varying baselines are accurate representations of their load profile, and who could provide cost-effective demand reductions at prices below the index. By

excluding such legitimate market participants we lessen the market benefits that could accrue to all New England consumers.

He emphasized what would be needed instead to properly address the baseline issue:

“[a]ccurate representation of the customer’s normal load is necessary to measure and verify that the load reductions indeed occur, so that demand response providers get paid for their service . . . ;” “[a] more precise tool is needed – a customer baseline methodology that accounts directly for seasonal shifts in customer load and for scheduled demand changes such as vacations, maintenance outage, and plant shutdowns” and that “a solution is needed sooner rather than later.”

ii. MISO (Docket No. ER08-404)

On April 22, 2008, FERC conditionally approved MISO’s emergency demand response (“EDR”) plan to provide compensation for load reduction during a NERC level 2 or 3 energy emergency. Under the plan, an entity that wants to be compensated for reducing demand or increasing output of behind-the-meter generation during energy emergencies must submit an offer at least one month ahead of the relevant operating month, and the offer must remain in effect for the entire operating month. The offer must include: (i) minimum and maximum amounts of demand reduction and continuous hours committed to reduction; (ii) costs associated with shutdown; (iii) the advance notice required to reduce demand; (iv) constraints on hours during which operations can be shut down; and (v) a dollar per MWh offer. Additionally, EDR offers are subject to a \$3500 per MWh (wholesale) cap; cost recovery is guaranteed to a participant that responds to a dispatch instruction by the greater of 5MW or 95% of the amount specified by MISO; penalties will be charged based on the real-time LMP of the host load zone for failures to reduce demand between the level specified

in the dispatch and a tolerance band; and EDR offers will not be able to set the LMP.

FERC approved the provision disallowing EDR to set the LMP on the basis that scarcity pricing provisions provide an incentive for demand resources to participate while MISO conducts certain system upgrades, but conditioned approval on MISO completely the upgrades quickly and submitting quarterly progress reports. FERC also directed the grid operator to clarify that historical behind-the-meter generation is not excluded from participating in the program, and to revise the tolerance band to clarify that resources providing less than 5MW of demand reduction will not be unfairly exposed to penalties.

Commissioner Wellinghoff issued a partial dissent on the basis that certain conditions to the plan would limit its effectiveness in attracting additional EDR. In particular, he found unduly onerous the requirement for a binding offer 30 days before the start of the operating month and the penalties for nonperformance. Commissioner Wellinghoff expressed support for some aspects of the EDR plan:

I agree that demand resources are a critical element of strong, competitive electricity markets, and that the benefits of demand resources are far-reaching. While Schedule 30 is limited to certain emergency events, it does represent a new opportunity for demand resources to be compensated for their role in preserving the reliability of Midwest ISO's system.

Schedule 30 has several laudable features. For example, an EDR can specify in its offer price its shutdown costs associated with a demand reduction, including direct labor and equipment and/or opportunity costs. If dispatched, the EDR will receive the higher of the applicable real-time LMP or the EDR's offer price. Thus, at a minimum, the EDR will receive its production costs. Schedule 30 also provides some flexibility with regard to measurement and verification procedures.

Respecting the binding offer and penalty provisions, however, he concluded as follows:

I do not believe that the inadequacy of Midwest ISO's systems is a sufficient basis to conclude that it is just and reasonable to require that EDR offers be made for a minimum of 30 days and not be modified without 30 days notice. No comparable requirement is placed on generators. In addition, the commenters

suggest that Midwest ISO’s current load management procedures could accommodate a work-around to permit EDRs to submit updated availability information on a timely basis until Midwest ISO can improve its systems. The absence of such a work-around may preclude Midwest ISO from calling upon demand resources that are otherwise willing to participate during an emergency. I would have directed Midwest ISO to file such a plan.

The flaw in Midwest ISO’s proposal is that an EDR is required to stand ready to provide a demand reduction service (*i.e.*, a capacity obligation) without any compensation. A penalty for non-performance is appropriate where an EDR receives a payment to be “on-call”. A penalty to ensure compliance may be appropriate if the EDR has the ability to make a timely modification to its offer. Here, the EDR is not compensated for standing ready to serve nor given the opportunity to make a timely modification to its offer. Given these circumstances, the assessment of a penalty has not been justified. Therefore, it would also be acceptable to me to make the EDR program voluntary without a penalty provision, as structured in PJM, NYISO and ISO-NE.

Commissioner Kelly issued a partial concurrence that demand response aggregators should be allowed to participate in the program: “Given that the program is meant to allow [MISO] to respond to emergency conditions, ... it is all the more important to ensure the participation of as many entities as possible....” She suggested that MISO amend its rules to allow the participation of aggregators for retail customers where the laws and regulations of the relevant electric retail regulatory authority would so permit. Commissioner Wellinghoff also supported this view.

iii. PJM (Docket No. ER08-824)

PJM’s tariff filing to revise its demand response baseline methodology is pending. Currently, PJM uses a “flat average” approach that looks to the five highest-usage days out of a 10 day period. PJM is of the view that this methodology “has the potential to miss the normal low-usage periods for highly variable loads” Among the changes proposed by PJM is to calculate the baseline based on the highest four days of the five most recent usage days preceding the day of curtailment. According to PJM, the result will be improved

accuracy because the baseline days will be closer to the curtailment day and averaging over four days will mitigate the effect of any particular day. Notably, PJM's filing was less strident than that of ISO-NE; whereas the latter had alleged inappropriate behavior and gaming – claims that are being investigated by FERC enforcement staff – PJM cited the objectives to “assure the integrity of demand response in PJM, reduce disputes between participants regarding registration and settlement, and improve the overall efficiency of the program. Among other proposed changes are to require that load reductions be in response to price in order to receive credit, to establish a list of activities that would not be considered demand response, and to require demand response providers to give notice if normal operations will cause a significant change in its customer baseline.

Several parties intervened by the May 5, 2008 deadline.

E. SPP Plan for External Generator Participation in Real-Time EIS Market Conditionally Approved (FERC Docket Nos. ER08-340, ER06-451)

On April 21, 2008, FERC conditionally accepted SPP's revised plan to incorporate external generators into its real-time energy imbalance service (EIS) market through a pseudo-tie mechanism. Under the plan, power is sold as if there were a direct tie between a generator and destination, however the physical movement of the power requires coordination between an SPP utility and an external balancing authority. FERC had encouraged SPP to consider using dynamic scheduling as an alternative, but came to agree with SPP that the pseudo-tie is more cost effective.

On October 15, 2007, FERC had rejected SPP's earlier plan for the participation of external generators in the RTO's EIS market because the plan placed the entire financial burden of accessing the markets on the external generators rather than apportioning among all parties, internal and external. The likely effect, FERC said, would be to deter external generators from

entering the market, and thus SPP issues of market power and bid insufficiency would remain unresolved.

Under the revised plan, submitted in December 2007, internal costs associated with providing access to the EIS system by external resources are allocated among all users of SPP’s transmission system. External participants will bear “external costs that depend on their unique situation.” FERC generally accepted the plan, but noted that certain entities (e.g., a source balancing authority) should not be saddled with the additional costs if in fact they do not benefit from the participation of the external generators in the EIS market. Thus, external generators will be required to compensate source balancing authorities for any costs incurred to provide services under the pro-forma agreement implementing the plan. Parties that are unhappy with the terms of the agreement are still free to negotiate individual terms and conditions that could then be filed with the commission. SPP had also suggested that source balancing authorities provide regulation and imbalance services for external generators participating in the EIS market. FERC disagreed and directed SPP to devise a mutually agreeable arrangement with source and sink balancing authorities. FERC also directed SPP to explicitly state in its pro forma agreement that all generators participating in the EIS market will receive equal treatment with respect to costs of regulation and imbalance services within the EIS market.

F. FERC Says Conference on PJM Capacity Market Performance is Premature (FERC Docket Nos. ER05-1410 and EL05-148)

A group calling itself the RPM Buyers Group asked FERC to hold a technical conference to examine the performance of PJM’s Reliability Pricing Model program (RPM) and to analyze eight specific issues related to PJM’s RPM. RPM Buyers expressed concern

that the program has resulted in increased prices without commensurate new capacity and reliability benefits. Based on the results of the first four residual auctions under the RPM, the group questions whether the mechanism is achieving its intended goals. RPM Buyers also expressed concern about the potential for the exercise of market power under RPM. They point to PJM's Market Monitoring Unit's finding of structural market power requiring mitigation of all RPM offers for the 2009-2010 RPM Auction and assert that due to the widespread application of administratively-determined mitigation, RPM auctions cannot be "competitive" and cannot produce reasonable capacity prices.

PJM asked FERC to await the outcome of an upcoming broad review of RPM by PJM and its stakeholders that PJM has already initiated before ruling on the need for a technical conference. The RTO has commissioned an independent assessment of the RPM auction results by an outside consultant, whose report is expected by the end of June.

FERC agreed with PJM that it would be useful to wait until PJM completes the evaluation and submits the outside consultant's report before determining if a technical conference is needed. 123 FERC ¶ 61,037. However, FERC noted that not all of the concerns raised by the RPM Buyers were addressed in PJM's proposed assessment and ordered PJM to expand the scope of its report to provide information in response to the specific issues raised by the group.

II. COURT PROCEEDINGS

A. Challenge to FERC's PURPA Sec. 210(m) Implementation Rules (U.S. Court of Appeals for the D.C. Circuit, Case No. 07-1328)

On August 16, 2007, the AF&PA filed a petition for review in the D.C. Circuit challenging FERC's new rules implementing PURPA Section 210(m) establishing the procedures and

conditions under which a utility may seek relief from PURPA mandatory QF purchase obligations. (Order Nos. 688, 117 FERC ¶61,078 (October 20, 2006) and 688A, 119 FERC ¶61,305, (June 22, 2007).)

The rules in question represent FERC's fulfillment of Congress' mandate in EAct 2005 to grant utilities waivers from the PURPA QF purchase obligation if certain conditions described in the statute are met. On rehearing, FERC rejected the argument that Congress intended that there be a meaningfully competitive market prior to terminating a QF's purchase obligation and that such markets that do exist are predominantly for resale and very short-term. In a key passage, FERC asserted: "Congress could have stated a broad general finding to be made by the Commission such as 'workably competitive markets.' Instead Congress tailored subparagraphs (A) and (B) to establish criteria specific to each market design...". Order No. 688-A at para. 47. "While it is true that EACT 2005 did not repeal PURPA or the Commission's obligations to encourage QF development, enactment of section 210(m) of PURPA clearly changes the rights of QFs under PURPA. The Commission has no discretion other than to terminate the purchase requirement if it finds that a QF has nondiscriminatory access... It would be inappropriate for the Commission to ignore this mandate... in a way that undermines the specific standards of relief that Congress chose to establish in the statute." *Id.*, at para. 48.

FERC stressed most heavily the different standard that Congress applied in Section 210(m)(1)(B)(ii) which requires a finding of access to "competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy including long-term, short-term and real tie sales." Such language is not contained in (A)(ii) which only requires access to markets. Order No. 688-A, at para. 24. Even if Day 2 long-term markets are nascent, Congress in (A)(ii) only required that the Commission finds that they

exist, not that they be robust. *Id.*, at paras. 26, 28. Without much rationale, FERC also found that the one-year term used for EQR reports is sufficient to meet the statutory requirement that there be “wholesale markets for long-term sales of capacity and energy” within the meaning of section 210(m)(1)(A)(ii). *Id.*, at para. 27.

The D.C. Circuit has granted ELCON’s motion to participate as *amicus curie* in support of AF&PA. Our draft of ELCON’s brief focuses on two issues relating to long-term contracting in seeking reversal and remand of Order 688 because FERC failed to properly apply the statutory criteria and failed to properly address comments specifying the nature of the long-term contracting needed to support the special operating characteristics of QFs.

First, the brief argues that FERC erred as a matter of law in concluding that the mere existence of the so-called “Day 2 markets” and, on rehearing, its reference to evidence of some bilateral contracting in those markets, satisfies the statutory standard of non-discriminatory access to long-term contract opportunities. The Day 2 markets are in their infancy: FERC itself recognized in two contemporaneous rulemakings that the absence of a forward market is in fact one of the principal problems confronting the nascent wholesale markets.

Second, the brief argues that FERC erred in defining “long-term” contracts for purposes of section 210(m) as those with a duration as short as one year, based merely on selective reference to inapposite FERC precedent. FERC failed to grapple with comments by ELCON and others establishing that contracts of on the order of five years duration are important to support investment in and construction of cogeneration facilities and other QFs, particularly in view of their special characteristics for dispatch of electricity. In the absence of a statutory definition or legislative history, FERC should be guided by the purpose of

section 210(m), which was not to remove incentives to QFs -- important as they are to the electricity grid and achievement of improved energy efficiency -- but rather to establish conditions whereby the deregulated wholesale markets can properly serve as a reasonable substitute for the mandatory purchase obligations of PURPA that otherwise would apply.

AF&PA's brief is due May 16, and ELCON's brief is due June 2. Oral argument has not yet been scheduled but is anticipated to be this fall, as final briefs are due in early September.

B. D.C. Circuit Rejects Application of Mobile-Sierra to ISO-NE FCM Settlement (Case No. 06-1404)

While upholding FERC's approval of the ISO-NE's planned capacity market structure, the D.C. Circuit rejected application of a public interest standard of review to challenges to transition payments and final auction prices brought by non-settling parties. *Maine PUC v. FERC*, 2008 U.S. App. LEXIS 6465 (March 28, 2008). According to the court, the *Mobile-Sierra* exception to the just and reasonable standard for rate review required by Section 206 of the FPA is only applicable between contracting parties and cannot be applied in a case of "non-settling third parties who have vociferously objected to the terms of the settlement agreement" for the simple reason that a contract cannot bind a third party.

The FERC decision under review involved FERC's approval of a settlement reached between 107 of 115 parties involved in the proceeding that established the ISO-NE's Forward Capacity Market (FCM) mechanism, which replaced an earlier proposed demand curve capacity market structure. 115 FERC ¶ 61,340 (2006). Under the FCM, annual auctions for capacity are to be held three years before such capacity is anticipated to be needed. The three-year lead time is designed to allow for a planning period for new entry and to allow

potential new capacity to compete in the auctions. The parties to the settlement agreement had negotiated a series of fixed “transition payments” to be paid to generators during the three year gap between the first auction and the time when the capacity procured at that auction would be provided. According to the settlement, challenges to these transition payments and to final forward FCM auction clearing prices are subject to the public-interest *Mobile-Sierra* standard of review, whether such challenge is brought by a settling or non-settling party.

The D.C. Circuit emphasized that the *Mobile-Sierra* doctrine is premised upon parties having voluntarily agreed to particular terms, which is not applicable in the context of the non-settling parties in this case. The court found FERC’s argument that application of the public interest standard was reasonable because it would only apply to future challenges to transition payment and to the final auction clearing price absurd. This assertion, said the court, is “equivalent to arguing that FERC will use an illegal standard sparingly.”

FERC had also argued that application of the *Mobile-Sierra* doctrine was necessary to promote price certainty and contract stability. Again the court disagreed. “The *Mobile-Sierra* doctrine is designed to ensure contract stability as between the contracting parties – i.e., to make it more difficult for either party to shirk its contractual obligations. It makes no sense to say that the values of ‘stability’ and ‘certainty’ are furthered by applying the deferential standard of review to the eight parties that refused to agree to the terms of the settlement.”

On the other points raised on appeal, the court sided with FERC. Petitioners had argued that the approval of the settlement’s transition payments was arbitrary and capricious because FERC is not required to rely on generators’ costs to determine rates. The

court found that FERC had not “plucked the rates out of thin air,” but rather had relied on evidence in the record to establish a reasonable range of capacity prices that was used as a basis to establish the transitional payments. The court also rejected challenges to FERC’s approval of the use of non-locational pricing during the transitional period. “[T]he fact that the transition period lacks a locational component does not change the fact that the ultimate result of the settlement proceeding is a new market structure that does account for location.” And finally, the court rejected the argument that approval of the FCM scheme exceeds FERC’s statutory authority because it forces utilities to purchase a specific amount of capacity. Because the forward market is designed to address pricing, it falls squarely within FERC’s jurisdiction. Moreover, approval of the installed capacity requirement is currently being challenged in another proceeding pending before the D.C. Circuit. (*Connecticut Department of Public utility Control v. FERC*, Case No. 07-1375).

C. D.C. Circuit Upholds Cal-ISO’s Gross Load Cost Allocation with Exemption for Certain Behind the Meter Generation

In *Western Area Power Administration v. FERC*, No. 04-1090 (May 2, 2008), the D.C. Circuit affirmed the outcome of FERC’s lengthy proceedings dealing, in relevant part, with the imposition of and exemption from administrative fees by Cal-ISO. In Opinion Nos. 463 (May 2003), 463-A (Jan. 2004), 463-B (Nov. 2005) and 463-C (Sept. 2006), FERC struggled with an evolving factual record to uphold Cal-ISO’s allocation of its Control Area Service charges on a gross load basis while applying its stated principle that “generators that will not cause the ISO to incur expenses should have their load exempted from the charges.” FERC ultimately concluded in Order 463-B (and affirmed in Opinion 463-C) that behind-the-meter generation not modeled by Cal-ISO – an appropriate proxy for costs incurred – is properly exempted from such charges, and it cited as an example “a behind-the-meter 10

MW generator which served its own load except for two weeks a year when it was off-line for maintenance.” On the other hand, FERC stated that “[i]f the ISO decides that the information regarding behind the meter generators is relevant to its studies and system modeling, then those generators are ineligible for the exemption because they are significant for study and modeling purposes and thus ultimately relate to administrative costs incurred by the ISO.”

The court based its decision on traditional deference to the agency under the loose "arbitrary or capricious" standard of judicial review, not a substantive determination against the allocation of costs to behind-the-meter generation under all circumstances. In this regard, the statements of the guiding principles quoted by the court -- that "all approved rates reflect *to some degree* the costs actually caused," "we have *never required a ratemaking agency to allocate costs with exacting precision*," and "FERC is not bound to reject any rate mechanism that tracks the cost-causation principle *less than perfectly*" – would give FERC some flexibility in applying connections between rates and costs in future cases. The court also referenced administrative convenience as a permissible criterion for FERC to apply.

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