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ELECTRICITY LAW DEVELOPMENTS – June 8, 2007

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 May 2007 issue of Electricity Law Developments are **in bold**. Please note that the next issue will appear in September 2007.

I. FERC PROCEEDINGS

A. FERC Issues Final Rule on Applicability of NERC Reliability Standards To QFs (Docket No. RM07-11)

FERC issued its Final Rule on the applicability of NERC reliability standards to QFs on May 17. Order No. 696, 119 F.E.R.C. ¶61,149 (FERC 2007). The Order is an excellent result for the interests of QFs as advocated by ELCON and AISI because the Order corrects the inference in the NOPR suggesting that QFs above 20 MW would automatically be registered. The order also leaves in place favorable compliance registry criteria that would be used to exempt most QFs from any compliance obligations.

In the NOPR, FERC had proposed that QF generation is for all practical purposes similar to other generation and accordingly that QFs above 20 MW are subject to registration. The proposal raised concerns by ELCON and allies that the Commission had failed to distinguish between QF and non-QF generation; and that FERC was proposing to require registration of QFs above 20 MW even if they do not have a material impact on reliability. FERC's final order clarifies that QFs should not have a "generic exemption" from reliability standards:

1. The Federal Energy Regulatory Commission (Commission) revises its regulations governing qualifying small power production and cogeneration facilities, to eliminate the exemption of QFs from the requirements of section 215 of the Federal Power Act. From a reliability perspective, there is not a meaningful distinction between QF and non-QF generators that warrants a generic exemption of QFs from reliability standards.

The Commission noted that ELCON and AISI submitted comments focusing on materiality as a condition for registration and advocating that a netting concept be applied since often QF power does not reach the grid.

16. ELCON and AISI state that they do not oppose the registration of QFs if particular facilities are found to materially affect the reliability of the bulk-power system. ELCON and AISI state that in fact they have cooperated with NERC staff to draft registration criteria that would address the unique operational characteristics of cogenerators. ELCON and AISI state that, unfortunately, the NOPR proposes an automatic per se rule that would force the registration of all QFs above 20 MVA/MW regardless of whether a QF's operations have any effect on reliability. ELCON and AISI also ask the Commission to recognize that NERC has applied a "netting" concept that recognizes that often QF generation never reaches the grid, or does so on a limited basis.

The Final Order recognizes key points advocated by ELCON and AISI, i.e., that a) only QFs needed to maintain reliability should be registered and b) such a determination should be made on a case by case basis applying NERC criteria.

30. Whether a generation facility should be subject to reliability standards should depend on whether a generation facility is needed to maintain the reliability of the bulk-power system. The reliability criteria adopted by NERC and approved by the Commission, as well as the compliance registry process adopted by NERC and approved by the Commission, are designed to ensure that only those facilities needed to maintain the reliability of the bulk-power system are subject to the reliability standards. The ultimate decision with respect to individual generation units and/or plants is, and must be, made on a case-by-case basis. Thus, whether a particular QF or type of QF should be exempt from reliability standards is an issue that is more appropriately made in the context of NERC's establishment of registry criteria for owners and operators of generators, and in the context of NERC's compliance registry process. The reliability of the bulk-power system will be better protected by utilizing the NERC compliance registry process, which will ensure that no generator that is needed to maintain the reliability of the bulk-power system will be exempt from reliability standards, while excusing those generators that are not needed to maintain reliability.

FERC clarified that there is no requirement that all QFs above a certain size be registered:

35. ...All the Commission proposed to do in the NOPR, and all the Commission is doing here in the Final Rule, is to eliminate the generic exemption of QFs from section 215 of the FPA and thus from mandatory reliability standards, thus treating them like other, non-QF generators for reliability purposes. The Commission was not proposing to, and does not, require that all QFs be subject to reliability

standards no matter their circumstances. Rather QFs and non-QFs alike would have an equal opportunity to not be subject to reliability standards. But that would be a case-by-case determination based on the circumstances of each case.

FERC noted that any entity that disagrees with NERC's determination to place it on the registry could appeal to the Commission.

In a paragraph directly responsive to ELCON's and AISI's concerns, FERC specifically acknowledges that QFs may qualify for exemption regardless of size if they primarily serve behind the meter, or have contractual arrangements transferring responsibility for reliability to another registered entity. FERC concludes that few QFs are likely to be registered.

37. The Commission notes that because of the operation of the size sections of the NERC registry criteria applicable to generators (i.e., greater than 20 MVA), only 23 percent of all QFs would meet this generally applicable threshold of 20 MVA (although some other QFs may be specified as either blackstart units material and designated as part of a transmission entity's restoration plan or as generators material to the reliability of the bulk-power system) and so would be subject to reliability standards. While some QFs may be classified as blackstart or as "material" to the reliability of the bulk-power system, and so made subject to reliability standards, other QFs may qualify for exemptions because, despite their size, either as a QF that is a cogeneration facility that primarily serves behind the meter load such that the net capacity supplied to the bulk power system is less than the size threshold for compliance, or as a QF that has contractual arrangements to transfer responsibility for compliance with reliability standards or associated requirements including reporting to another entity that has registered with NERC. The net effect is that the universe of QFs that will be affected by this Final Rule, by virtue of operation of the NERC registry criteria, is likely to be relatively small.

B. Duke and AEP Request Relief from Mandatory QF Purchase Obligations (Docket Nos. QM07-2-000 and QM07-4-000)

On May 17, 2007, FERC unanimously granted Duke Energy Shared Services request for relief from QF purchase obligations, finding that no party had rebutted Duke's claims in its application. Following staff's presentation at the

May 17 meeting, the Commissioners had the following questions and comments:

- **In response to questions from Chairman Kelliher, staff noted that only one other petition (from AEP) had been filed to date and confirmed that the Duke petition related only to its Midwest operations.**
- **Commissioner Wellinghoff noted that Duke’s petition did not apply to QFs of less than 20 MW.**
- **In response to a question from Commissioner Moeller about whether there was a risk that QFs might not receive notice of these petitions, staff observed that (i) QFs typically have ongoing business relationships with utilities even if under construction or expansion, (ii) petitions are noticed in the Federal Register, and (iii) in the highly unlikely circumstance that a QF nonetheless did not receive notice (e.g., because of a clerical error), it could file for reinstatement per the final rule or seek a “correction of error” from FERC.**
- **Commissioner Kelly asked for staff’s recommendations about changes to the petition process, particularly relating to additional information that the utilities should provide, in light of experience with this first one (to which staff devoted considerable effort). Staff noted that they had been “kicking around some ideas”, and referenced the pending rehearing, but declined to provide specific suggestions at this time. Commissioner Kelly said that more information about the QFs involved would have been useful but noted that none had chosen to file oppositions, she presumed because Duke had established amicable, forward-looking relationships with its QFs.**

On March 21 and April 18, 2007, respectively, Duke Energy (Duke Midwest Companies) and AEP have each filed with FERC petitions for relief from the mandatory PURPA QF purchase obligations on a service territory-wide basis. The Duke filing applies only to the former Cinergy service territory. The AEP filing applies to "AEP East."

In October 2006, FERC issued Order No. 688 implementing new PURPA section 210(m) and outlining the criteria and procedures by which utilities in organized markets could apply for relief from QF purchase obligations. 117 FERC ¶61,078 (Oct. 20, 2006). In the rulemaking proceeding, ELCON had urged that problems in the organized markets including lack of long-term contracts make it inappropriate to generically relieve utilities from purchase obligations in the organized markets. FERC found that the absence of a viable long-term contract market was not statutorily required. However the final rule rebuttably presumes that QFs below 20MW lack access, while QFs that are above 20MW can show that they lack access by reference to specific operational characteristics or by showing that they lack access to distribution facilities. The final rule also calls for a "facility-specific" determination of access and requires that utilities provide information on transmission constraints and congestion that would not otherwise be available to QFs.

The applications that AEP and Duke have filed are tailored to the filing requirements that FERC established. Each application accordingly provides information on transmission constraints and addresses the QF facilities that would be affected.

AF&PA filed a late intervention in the Duke proceeding on May 1, claiming it did not learn of the proceeding until after the intervention period had run. FERC denied the motion to intervene on the grounds that (a) publication in the Federal Register provided adequate notice of the application, and (b) APPA failed to demonstrate that it would be

directly affected by the outcome of the proceeding. Furthermore, issues raised by AF&PA in its filing, FERC stated, will be addressed on rehearing of Order 688, which is currently pending.

On May 15, 2007, ELCON filed an intervention urging FERC to issue its rehearing order on Order 688 before acting on AEP's petition for relief from PURPA mandatory purchase obligations. To do otherwise would be disruptive and wasteful of FERC's and the QF's resources since the rehearing may significantly impact the procedures and criteria for evaluating AEP's petition. In particular, ELCON argued that service procedures should be improved so that all QFs in a utility's service territory, irrespective of size, receive actual notice of a utility petition.

AF&PA also protested AEP's request, arguing that AEP has not met the statutory burden of a factual showing that there is meaningful competition in its footprint and that QF's have nondiscriminatory access.

AEP filed a response on May 31 asserting that neither ELCON nor AF&PA have standing in the proceeding.

FERC has not yet ruled on AEP's petition or on the motions to intervene.

C. State Consumer Advocates Complaint against PJM regarding MMU Independence (FERC Docket Nos. ER98-1440-000 & EL07-56-000)

History of the Proceeding:

A large group of state consumer advocates, and cooperative and municipal utilities, and the industrial group PJMICC filed a complaint with FERC (the "Joint Petition") on April 17, 2007, urgently seeking Commission action in light of statements by PJM that it is considering abandoning its current internal market monitor and statements by the PJM Market Monitor

(MMU) that its independence is being compromised by PJM management and that the MMU is being starved of the resources and personnel need to do its job. PJM has reacted by delegating to its outside counsel the task to perform an “independent” investigation of the situation.

On April 30, 2007, ELCON filed comments in support of the Joint Petition and also urged FERC to reject PJM's effort to investigate itself on this matter.

ELCON urged the Commission to give its most careful consideration to the serious issues raised by this petition. ELCON took no position on the merits of the allegations concerning PJM's actions *vis a vis* the MMU, or to the counterclaims of PJM management. However, ELCON noted that the Joint Petition is filed at a time when the Commission's organized markets are under challenge and criticism. ELCON cautioned that inattention by the Commission to the integrity of the PJM market monitor could undermine confidence in PJM and other RTOs at a time when the efficiency and independence of these markets is under growing public scrutiny. In particular, ELCON expressed concern that the weakening of the market monitor watchdog will only exacerbate these problems. The independence of the market monitor is key to pointing out market failures and illegal behavior, and recommending changes that can correct these problems and make organized markets more competitive.

ELCON commented that regulatory agencies must exercise special vigilance when regulated entities propose to discontinue reliance on entities that have served as independent monitors of their activities. PJM filed comments in this docket shortly after the Joint Petition was filed promising an “independent investigation.” ELCON urged FERC in the first instance to adjudicate the merits of the claims raised by Joint Petitioners and give no deference to a review process administered by the RTO that has been charged with improperly undermining its MMU.

ELCON also encouraged FERC to revisit its 2005 Policy Statement on Market Monitoring and correct the current state of uncertainty over implementation of MMU independence.

Recent developments:

On May 18, 2007, FERC issued an order denying interim relief based on the factual nature of the dispute, but agreeing to fast-track the complaint. PJM and its market Monitor were ordered to respond within 10 days (later extended until June 12) to data requests aimed at assessing whether tariff violations indeed have occurred and whether PJM has in fact done anything to prevent or obstruct the MMU from performing its obligations under the tariff.

D. Conference on Demand Response (Docket No. AD07-11)

On April 23, 2007, FERC held a technical conference on demand response in wholesale markets. The conference was initially intended to examine the potential role of demand resources in upgrading transmission infrastructure, but was then broadened to examine the role of demand response in wholesale markets in general. Among the panelists participating were representatives from the organized markets and from NERC.

PJM identified two key elements of a planning process that integrates demand resources as an alternative to transmission upgrades: information and transparency. Since demand response resources are essentially an unregulated resource, demand response will flourish when providers have the information necessary to make the business case for their particular demand response resource.

PJM explained that, in its transmission planning process, it does not determine the most economic solution by reviewing demand response, generation and transmission.

Rather, PJM relies on certain assumptions concerning demand response resources to provide information needed to assess the costs and benefits of a particular transmission upgrade that otherwise might be considered to address a reliability violation or alleviate congestion, *i.e.*, information on “what it would take” to avoid the upgrade.

In response to a question from FERC regarding the current advantages, challenges and obstacles to the implementation of demand resources as an alternative or complement to transmission facilities additions, PJM offered that the main barrier to demand response is the lack of common standards across the wholesale marketplace and the decentralized nature of demand resources.

ISO-NE reported that they are currently implementing a Demand Response Reserves Pilot Program to determine if small generation and demand response resources (<5 MW) can provide a functionality equivalent reserves product. They explained that there are currently more than 900 MW of demand response resources enrolled in ISO-NE’s programs; however, they see significant potential for additional growth in this area.

In the new Forward Capacity Market, both generation and demand resources will be eligible to participate and a portfolio of supply and demand resources are expected to be selected. With the new market mechanisms in place, implementation of demand response resources as part of the day-to-day market structure in New England is not that difficult. Challenges continue to be the relative size and specific location of the demand response resources versus that of new generation or the magnitude of system benefit gained from major new transmission projects. In a system-wide power supply shortfall that can be projected up to 30 minutes in advance, ISO-NE stated that “operator controlled” demand response does an outstanding job. However, where there is the sudden loss of a

transmission element that causes an immediate voltage collapse, thermal overload, or instability on the power system, demand response cannot be counted on to mitigate the need.

NYISO reported that over the past five years, its demand response programs have grown by approximately seven percent annually. NYISO explained that in order to fully integrate demand response, significant movement must occur at the retail level; customers need to be exposed to wholesale market prices and have the ability to see and react to those prices in real time. Wholesale market designs can best deal with customers who are enabled with the proper real-time interval metering and whose load is either directly (through LBMP) or indirectly (through contracts for differences) subject to wholesale market pricing. Not all loads need to be exposed at this level; if fifteen to twenty percent of customers were able to react to wholesale prices, this would likely provide enough demand elasticity to put demand and supply on equal footing.

MISO agreed that markets work best where there is vigorous participation by both buyers and sellers. To truly have demand response, end-use customer participation is critical. At present, MISO has no formal demand-side program. Like PJM, MISO is looking closely at the link between the retail markets and the wholesale markets and is focusing on price transparency and accurate price signals.

One major obstacle in the MISO region is customer education and training. Most MISO states are under rate regulation environments, thus the link between wholesale markets and retail rates needs to be addressed. A second major obstacle is the risk-averse nature of control area operators, which leads to some initial discomfort with demand response and provision of contingency or operating reserves.

CAISO explained that in California infrastructure is being put in place to increase demand response, including implementing market restructuring, setting aggressive demand response goals and implementing the advance metering initiative. These measures, however, are not as far along as CAISO hoped they would be at this time. Nevertheless, CAISO has learned important lessons for a successful demand response program: (1) CAISO must get the market right for demand response to be integrated into the wholesale market; (2) CAISO must work closely with state agencies, FERC, investor owned utilities and load serving utilities; (3) aggregators can bring new customers and grow programs – and at the same time provide reliable demand response quantities; and (4) CAISO must understand the end user’s needs.

NERC’s comments focused on measurement and evaluation of demand response resources. In reliability assessment reports, NERC documents the amount of demand reduction expected through two specific types of demand response programs: direct control load management and interruptible demand. NERC also reported that it is launching a study on the influence of demand response programs on reliability in conjunction with its *2007 Long Term Reliability Assessment*. The goal of this study is to identify what programs influence reliability and adequacy, suitable models for analyzing these impacts, and data collection requirements. NERC expects to incorporate enhancements from this work in its seasonal and long-term reliability assessments beginning in 2008.

**E. FERC Holds Second Conference on Wholesale Competition
(Docket No. AD07-7)**

On May 8, 2007, FERC held the second public conference in its series on the state of competition in wholesale power markets, which FERC hopes will serve to adjust the mix between reliance on competition and regulation. Chairman Kelliher opened the conference by stating that he expects FERC to make a number of significant policy changes in the near future, though he didn't elaborate on what they might be. Issues discussed during the conference included ways to improve demand response, opportunities for long-term power contracting in centrally organized markets, and the responsiveness of RTOs and ISOs.

Demand Response

The panel on demand response addressed the need for a more direct connection between wholesale and retail markets. Illinois Commerce Commissioner Robert Lieberman insisted that the first problem is that the wholesale markets are too often viewed as independent from retail markets, and that supply-side competition is considered apart from demand side response to prices. Second, he suggested that consumers need to be educated about the benefits of direct participation in the markets while the industry needs to develop more advanced metering and billing system.

Bill Hogan of Harvard University suggested that the first step is even more fundamental – get the market design right. He then noted that scarcity pricing, which is present in some degree in the energy markets, is absent with respect to operating reserves. He suggested that better scarcity pricing implemented through the operating reserve demand curve would provide an important signal and incentive for flexible demand participation in spot markets.

David Meade of ELCON cautioned FERC that while scarcity pricing is an issue, large industrial consumers are not likely to favor uninhibited scarcity pricing until effective wholesale competition in the markets is implemented.

Long-term Power Contracting

This panel debated the existence of opportunities for long-term power contracting in organized markets, with several panelists concluding that for the most part such opportunities are lacking for the simple reason that it is often more lucrative for sellers to sell into the spot markets. Furthermore, where such contracts do exist, they often are a pass-through mechanism of peak spot market prices.

Others commented that the main obstacle to long-term contracting is not the structure of RTOs or federal regulatory barriers, but rather a problem of risk perception, particularly related to environmental laws and siting obstacles.

RTO and ISO Responsiveness

Another panel discussion tackled the issues of accountability of RTO and ISO boards and adequate participant representation on these boards.

The suggestion was made that FERC mandate that boards be composed of a “hybrid” of members from different stakeholder groups, however, FERC’s authority to do so is limited.

ELCON Chairman Lloyd Webb explained that ISOs’ and RTOs’ stakeholder processes favor supply-side interests at the expense of demand constituents. Since ISO and RTO management are increasingly supporting suppliers, demand-side entities are becoming more engaged with defensive strategies. He commented that demand side interests should be represented on each ISO and RTO board.

Representatives from the RTOs and ISOs noted that there would likely be resistance to the pressure to create hybrid boards, given that most believe their boards are adequately representative and that their own requirements and methods of nominating members are sufficient.

F. FERC Adopts Transmission Cost Allocation Plan for PJM (Docket Nos. EL05-121, ER06-1271)

On April 19, 2007, FERC approved PJM’s plan for allocating transmission costs among in-area transmission service customers, reaffirming PJM’s current “license plate” rate design for allocating the cost of existing facilities and new owner-initiated facilities. Under a license plate design, each utility pays for transmission service based on the costs of transmission facilities located in the same sub-regional zone where the utility is located. This order affirms the findings of an ALJ in a July 2006 initial decision that the beneficiary of a project should pay its costs, but reverses the ALJ’s finding that utilities should pay a uniform “postage stamp” rate for access to the regional transmission grid. 119 FERC ¶61,063.

The Commission agreed with the ALJ’s finding that, although the grid today is operated on an integrated basis, that fact alone “does not support a reallocation of sunk transmission costs within PJM.... The current license plate rate design remains just and reasonable because it reflects the prior investment decisions of the individual transmission owners.” FERC noted that the facilities in question were built principally to support load within the individual transmission owners’ zones and continue to serve those loads.

Concerned that the methodology for determining who benefits from a project is not sufficiently detailed and invites litigation each time a new project is proposed, FERC in a

separate order directed PJM to develop a detailed methodology to be included in PJM's tariff for determining who benefits from, and therefore, who pays for new facilities – both reliability projects and economic projects – below 500 kilovolts (kV). 119 FERC ¶61,067. The methodology may use different criteria for reliability versus economic projects, “if justified on the record.” However, FERC also determined that the costs of all new PJM-planned facilities that operate at or above 500 kilovolts – both reliability projects and economic projects – should be shared on a region-wide basis because the benefits are sufficiently broad to permit a postage stamp rate.

G. Approval of Long-Term Transmission Rights Proposals Granted to Both MISO and PJM (Docket Nos. ER06-1218, ER07-478)

On May 17, 2007, FERC largely approved proposals on long-term transmission rights (“LTTRs”) in PJM and MISO.

In July 2006, the Commission finalized guidelines for independent transmission organizations for the development of LTTRs. Order No. 681, 116 FERC ¶ 61,077 (July 2006). The final rule implemented section 1233(b) of the Energy Policy Act of 2005, which directed the Commission to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of LSEs and enable LSEs to secure LTTRs to meet such needs. The rule directed ISOs and RTOs to make LTTRs available. Such rights are aimed at providing an added degree of certainty to LSEs that plan to enter into power supply agreements, which in turn should help LSEs in obtaining financing for new infrastructure.

In November 2006, FERC had conditionally approved PJM's proposal but found a number of shortfalls to be addressed, including the lack of a mechanism to assure that LTTRs would be fully funded because there was not uplift mechanism to make up for any

shortfalls in congestion revenues. To address this problem, at least initially, PJM will allocate uplift charges to all FTR holders on a pro rata basis according to the total target allocations for all FTRs held throughout the planning year. In the May 17 order, FERC accepted this solution but directed PJM to file a status report on discussions with stakeholders on other possible solutions to the problem. 119 FERC ¶ 61,144.

The May 17 order also addresses the issue whether LSEs outside PJM may obtain LTTRs on the same basis as LSEs within PJM. According to Order No. 681, in order to receive LTTRs an external LSE must have an existing agreement with the ISO or RTO to pay some of the embedded costs of the transmission system on a long-term basis. If an LSE does not meet this condition, FERC decided, it is not entitled to receive LTTRs on equal footing with internal LSEs.

The Commission accepted the Midwest ISO's proposal for LTTRs, with some modifications. MISO's proposal introduces a new framework for the allocation and trade of transmission rights in its markets. Notably, the current approach, under which there is a direct allocation of point-to-point FTRs, will be replaced by the direct allocation of point-to-point ARRs followed by an auction for FTRs. In addition, the annual schedule for ARR allocation and auction of FTRs will be changed. These changes were planned initially to support development of a joint and common market between MISO and PJM, which would now share some common market rules for transmission rights and the same calendar for their transmission markets. MISO will also adopt certain aspects of PJM's approach to LTTRs, which essentially involves creating a subset of long-term ARRs, although differences will remain.

MISO’s proposed tariff changes include the rules for implementation of ARRs, and a description of both the ARR-related tariff revisions and the proposed LTTR procedures. Many of the features of the current FTR market design will remain or be modified slightly. For example, MISO proposes that the ARRs are point-to-point obligations, covering seasonal as well as on and off-peak periods, just as FTRs are currently defined within the Midwest ISO. As is currently done with FTRs, it plans to annually allocate ARRs; the ARR recipient can either directly convert the ARR into an FTR with equivalent specifications (called “self-scheduling”) or can choose to receive revenues associated with its ARR from the annual auction of FTRs.

Similar to earlier findings with respect to PJM’s proposal, FERC found that under MISO’s proposal, FTRs would not be fully funded and as a result, violated one of the guidelines set out in Order No. 681. 119 FERC ¶61,143. The Commission directed the Midwest ISO to make a compliance filing with a mechanism and allocation method to support the financial transmission rights.

H. FERC Announces Technical Conference on Reliability Enforcement Issues in the ISOs and RTOs (Docket AD07-12)

Sparked by a proposal submitted by MISO outlining methodology for recovering penalties for violations of the new reliability standards, FERC has decided to hold a technical conference to address how ISOs and RTOs should enforce compliance with the new mandatory reliability standards.

On April 2, 2007, MISO filed proposed changes to its Open Access Transmission and Energy Markets Tariff (TEMT) in order to provide for recovery of penalties that are

imposed on it by FERC, the ERO or a duly authorized Regional Entity for violations of mandatory Reliability Standards. MISO proposed to directly assign the penalty costs to specific customers if it were able to determine that the violation is due to their non-compliance with MISO's directives or requirements, or with Good Utility Practice or any other applicable technical standards under the TEMT. Any direct assignment of penalty costs, however, will only apply following an FPA section 205 filing by MISO and Commission approval of the direct cost assignment. If MISO is unable to identify the specific tariff customer(s) responsible for the violation, the penalty costs will be allocated to all tariff customers based on the level of their energy injections and withdrawals from the MISO transmission system (the same billing determinants used for recovery of energy market administrative costs) during the months when the event associated with the penalty occurred.

FERC rejected the proposal without prejudice, finding that the issues raised concerning the Reliability Standard compliance and enforcement process may be common in other regions with ISOs and RTOs, and that these issues are best addressed on a generic basis. Pending the result of such generic proceeding, FERC stated that if the ERO or a Regional Entity files a notice of penalty with the Commission, or if the Commission initiates a proceeding to impose a penalty, MISO may seek to recover that penalty through an individual FPA section 205 filing.

FERC expressed concern that the direct assignment aspect of MISO's proposal "both will result in duplicative investigations of Reliability Standard violations -- in the context of any ERO/Regional Entity or Commission enforcement proceeding and any Midwest ISO FPA section 205 proceeding -- and also will result

in parties bringing issues directly to the Commission that should be addressed in the ERO/Regional Entity or Commission enforcement proceeding in the first instance.” FERC noted that it did not intend that section 205 proceedings initiated by ISOs and RTOs to recover penalty costs would involve new, additional investigations of violations of Reliability Standards beyond any investigations done in connection with the Commission’s, ERO’s or Regional Entity’s assessment, in the first instance, of penalties. In particular, FERC questions why a tariff customer that MISO would directly assign a penalty under its proposal would not already be registered with the ERO for compliance with the relevant Reliability Standard, and correspondingly subject to investigation and a penalty in the ERO/Regional Entity or Commission enforcement proceeding.

Additionally, FERC noted that MISO’s proposal does not address how responsibility for penalty costs is to be addressed between MISO and those owners and operators of the bulk-power system (such as transmission owners and balancing authorities) with which MISO has agreements allocating operational responsibilities outside of the TEMT. FERC asked: “Do such agreements present situations similar to those envisioned by Midwest ISO’s proposal, where Midwest ISO would be assessed a penalty for violating a Reliability Standard due to its counterparties’ failure to perform under such agreements? If not, could those arrangements serve as a model for tariff provisions and Reliability Standard compliance strategies that would avoid situations envisioned by Midwest ISO’s proposal with respect to Tariff Customers?”

Finally, FERC expressed concern about the lack of due process should entities directly assigned penalties not have had an opportunity to represent their interests in the ERO/Regional Entity or Commission enforcement proceeding.

The date of the conference has not yet been announced.

I. Connecticut AG Request for Stay of FCM Transition Payments in ISO-NE Markets Denied (Docket Nos. ER03-563, ER07-546, and ER07-547)

Transition payments under the ISO-NE's Forward Capacity Markets mechanism (FCM) may continue pending appeal in the D.C. Circuit, according to an order issued by FERC on May 17, 2007 rejecting an April 5 request by the Connecticut Attorney General for a stay of these payments.

On December 29, 2006, the Connecticut AG along with the Massachusetts AG, filed a petition for review with the D.C. Circuit of FERC's FCM orders. Docket No. 06-1427, *Richard Blumenthal, et al. v. FERC*. According to the April 5 Motion for Stay, New England customers will be required to pay \$5 billion in "transition payments" to all existing capacity throughout the course of the appeal, even if the court eventually finds that the payments are not just and reasonable, and retroactive refunds may be precluded in this case.

History of the proceeding

The Federal Energy Regulatory Commission had approved a settlement agreement addressing problems in New England's generation capacity market. 115 FERC ¶61,340 (June 16, 2006), Order on Reh'g, 117 FERC ¶61,133 (October 31, 2006). The settlement was the result of thirty formal settlement conferences over a four-month period overseen by a

Commission administrative law judge. Of 115 parties involved in the settlement proceedings, all but eight parties supported the settlement in whole or part.

Under the settlement agreement a forward capacity market (FCM) will be implemented instead of the contested locational installed capacity (LICAP) mechanism proposed two years earlier by ISO-NE. The FCM mechanism allows load-serving entities (LSEs) to self-supply through their own resources or contracted resources, thus an LSE can meet its capacity obligations, subject to the same performance obligations as other resources, without participating in the forward capacity auctions.

The settlement also provides for a transition period until June 1, 2010, which marks the start of the first period in which suppliers would receive payments under the FCA mechanism.

In an April 5, 2007 filing, the Connecticut AG asserted that FERC has no legal authority under the FPA to establish resource adequacy requirements for generation capacity, and that FERC failed to engage in reasoned decision-making in approving transition payments that “serve no legitimate regulatory purpose.” Thus,

The result of this improper \$5 billion windfall payment to all existing generation will be to push electricity rates in New England, already twice the national average and the most expensive region in the country, even higher.

Grant of a stay will preserve the status quo, the AG argued, by keeping distressed generators on cost of service reliability contracts, preserving the current installed capacity market rules, and ensuring that the rates charged are just and reasonable. Moreover, most of the transition payments will go to those generators that are already well compensated in the energy markets:

For those [well compensated] generators, the transition payments ... are pure largesse to gain supplier sign-on to the Settlement Agreement... . Suppliers that are recovering their costs in the energy

markets will be only too happy to receive the transition payments, while giving nothing in return to consumers for those payments.

On May 17, 2007, FERC rejected the AG's motion to stay, reasoning that it lacked jurisdiction to grant the request since the order approving the FCM settlement is currently pending before the D.C. Circuit. Even if it had authority, FERC stated, it still would have rejected the request since the AG failed to show that his state would suffer irreparable injury absent a stay -- a showing of mere *potential* economic losses is insufficient.

The order further explained that the AG's assertion that refunds of the transition payments would be unavailable to customers is premature. Should a court remand the approval of the FCM settlement back to the Commission, FERC will at that time, and in light of the court's directions to the Commission, determine what refunds – if any – might be appropriate.

J. CT AG Seeks DC Circuit Review of FERC Approval of ISO-NE Generator Compensation System (Docket No. EL05-150 FERC)

On May 8, 2007, the Connecticut AG sought DC Circuit review of FERC's approval of a hybrid compensation system for generators needed for reliability in the ISO-NE.

History of the Proceeding

On October 11, 2006, FERC denied a September 2005 complaint filed by the Connecticut AG, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Energy Electric Cooperative, and the Connecticut Industrial Energy Consumers against ISO-NE regarding the compensation for electric generation facilities in Connecticut that are needed for reliability. The AG et al. had asked that the ISO-NE's tariff, Market Rule 1, be amended to require compensation of all electric generation facilities in Connecticut on a

cost-of-service basis, through Reliability-Must-Run (RMR) agreements, until the Commission can determine that electricity markets in Connecticut are competitive and consistent with the just and reasonable standard of the FPA.

Under Market Rule 1, New England generators seeking RMR agreements must first file for a reliability determination from ISO-NE and may file a cost-of-service RMR agreement with FERC under section 205 if that generator is not satisfied with its current compensation.

Beginning in 2003, in the course of developing a competitive capacity market in the region, FERC had rejected several RMR agreements and had approved an interim measure -- the Peaking Unit Safe Harbor, of PUSH bidding -- to address certain market flaws so as to give low-capacity factor generating units operating in designated congestion areas the opportunity to recover their costs through the market. The ISO-NE was then directed to develop a permanent mechanism to implement a location-based or deliverability requirement in the ICAP or resource adequacy market, so that capacity located in designated congestion areas would be appropriately compensated for reliability.

Then, in 2004 and early 2005, the Commission accepted several RMR agreements and conditioned them to terminate on the day a location-based capacity or deliverability requirement was implemented. The Commission reasoned that accepting the RMR agreements for a limited term was appropriate, given that the units covered by the contracts were aging, low capacity factor units that were performing poorly under the PUSH bidding rules. Subsequently, FERC approved other limited-term RMR agreements for newer, baseload facilities needed for reliability that have demonstrated an inability to earn sufficient revenues to keep generation available to provide reliability services.

Request for Rehearing

On November 9, 2006, the Connecticut AG filed a request for rehearing of the Commission's October 11, 2006 Order, arguing that the failed "hybrid" system in Connecticut, made up of both regulated and market elements, deprives consumers of the benefits they should expect (*i.e.*, lower prices) if either a cost-based or market-based regime were to exist in isolation. According to the AG, the hybrid system has allowed high-cost generators to opt out of the market in favor of guaranteed cost-of-service compensation (through RMR contracts) far above what those generators would receive in a competitive region-wide market, while lower variable cost units operate as if there were an open, competitive market, thereby collecting "market" rates set by non-market participant high-cost generators.

The AG also contended that those units using PUSH bidding to recover their costs, are allowed to continue submitting energy bids that far exceed what would be expected in a truly competitive market. They have the opportunity to increase congestion costs in constrained regions and to collect uplift charges for out-of-merit operation when they are needed for local area reliability, even though other less expensive alternatives are available in the region-wide energy market. In addition, the CT AG avers that the Commission has allowed some generation owners to place certain units under cost-of-service compensation while keeping neighboring sister units for participation in the market, resulting in both regulated and unregulated generating plants, owned by the same corporate entity, operating side-by-side.

On March 15, 2007, FERC denied the rehearing request, reasoning that the AG's contentions do not turn on facts concerning any particular generator or market price. 118

FERC ¶ 61,205. With respect to the reasonableness of maintaining a “hybrid” system of cost- and market-based rates, FERC explained RMR contracts are only approved after (1) a generator is found to be needed for reliability; and (2) out-of-market financial arrangements are necessary to ensure that the unit remains available. These transitional contracts are necessary due to the lack of transmission infrastructure in Connecticut and (pre-FCM) insufficient capacity revenues, at least until the pending FCM mechanism is implemented. Moreover, any revenues that exceed an RMR unit’s annual fixed revenue requirement (*i.e.*, transition payments under FCM) are credited against these fixed RMR payments.

The DC Circuit has not yet ruled on this issue.

K. Gerdau tells FERC PJM misunderstands its own settlement procedures under ELRP (Docket No. ER07-508)

History of the proceeding:

In early 2007, PJM filed proposed revisions to its economic load response rules, explaining that the change was needed “to address the problem of entities engaging in activity using PJM’s demand-response market access which does not provide the demand-response benefits that PJM’s economic load-response program was designed to produce.” The existing rules allow participants in the program to buy and sell in the same day-ahead market upon which the retail LMP rate is indexed, but prohibit such activity in the real-time market. According to PJM, entities with day-ahead LPM-based contracts are able to game the system by submitting demand reduction bids in the day-ahead market when LMP is above \$75/MWh in order to receive the economic-load response incentive irrespective of whether they intend to consume energy for that period.

Gerdau Ameristeel Corporation (“Gerdau”) on February 23 filed a protest, citing, among other concerns, two issues of particular importance to ELCON members: first, PJM’s proposed revisions fail to treat demand response symmetrically with generation; and second, PJM’s assertion that a majority of stakeholders approved the plan does not paint an accurate picture of stakeholder support. ELCON filed comments February 23 in support of Gerdau’s protest on these issues. In particular, ELCON stated that PJM’s proposal does not treat demand response symmetrically with other resources. A decrease in a MW consumed has the same effect on the system as an increase in MW generated, therefore demand response should be treated symmetrically and priced on the same basis as a generator. PJM’s argument is that customers that take LMP prices should benefit only from the savings they receive by not buying power (the value of the LMP at the time) and not receive any incentive in addition to those savings. The same logic applied to a generator is that they save money (fuel costs) by not generating and therefore should be very happy if they are not generating. PJM is not proposing to ban generators from the day-ahead market because they might game their bids. ELCON commented that asymmetrical treatment of demand-side resources aggravates the problem of limited opportunity for demand resources to participate in the market.

On March 12, 2007, PJM filed a response urging FERC to reject the protests and approve its proposal. In general, they argue that generation and demand resources are in fact treated symmetrically in their proposed rule change, while the present system is problematic in that it contains an asymmetry that gives preference to demand side resources:

What [the protesting] parties ignore, or fail to understand, is both basic and essential to appreciating the reasonableness of the proposed rule – namely, that unlike other resources, notably generators, PJM’s programs to encourage demand side participation contain important subsidy and socialization elements. Except under limited operating scenarios, generators receive LMP for their supply. In contrast, demand side providers under fixed price contracts enjoy the fixed price

savings realized and the full LMP incentive payment when LMP is equal to or greater than \$75MWh. By not allowing those end-use customers exposed to LMP through their retail contracts an opportunity to realize this subsidy, PJM is, in fact, treating these resources “symmetrically” with generation.

On April 3, 2007, FERC notified PJM that its filing was deficient and directed PJM to supply additional information, including:

- An explanation of how PJM measures demand reduction benefits.
- An explanation of how bidding behavior of Day-Ahead LMP customers “negat[es] any real demand response from such customers”.
- An analysis of the effects of eliminating Day-Ahead LMP customers from the ELRP program and impacts on the market.
- Details of specific actions taken by customers that PJM considers gaming and an explanation of how the bidding behavior is similar to paying subsidies for wash trading.

PJM responded April 18, 2007, explaining that its position is:

...when a Day-Ahead LMP customer curtails its consumption as a result of a payment under the ELRP program, these load reductions do not produce net benefits to the PJM market. These load reductions result in non-efficient prices with negative impacts on the market. ... LMP customers ... already face the appropriate price signals. Allowing such customers to participate and receive the ELRP incentive results in economically irrational demand response because it provides an out of market subsidy. ...

While economically irrational response may result in less load on the system, such activity distorts efficient price signals and, therefore, undermines efficient market activity and investment.

PJM argued that exploiting loopholes in rules in order to reduce load on an economically irrational basis can distort prices that might otherwise signal economically rational demand reductions, either through rational consumption decisions or investments in energy efficiency. PJM also argued that the behavior is equivalent to gaming because “it exploits a loophole in the rules in a manner that is clearly not consistent with the intent of the ELRP. ... Under these

circumstances, an entity effectively buys and sells an equal amount of energy at the same price, which is similar in effect to a wash trade.” According to PJM, the entity then is paid the ELRP incentive for a set of transactions “comparable to wash trades” which do not provide any of the intended demand response benefits in return.

On May 9, 2007, Gerdau filed a supplemental protest responding to PJM’s April 18 filing, again urging FERC to reject PJM’s proposal. Gerdau identifies the following defects with the proposal and PJM’s subsequent filings: PJM elevates theory over practical reality; the grid operator misunderstands its own settlement process for cleared Day-Ahead ELRP bids; PJM ignores precedent in New England and New York; and PJM understates the process of obtaining PJM approval of a contract that would allow Gerdau to participate in the Day Ahead ELRP. Gerdau was especially troubled by PJM’s assertion that “there is no economically rational demand response when a customer’s assessment when a customer’s assessment folds into the calculus any Day-Ahead ELRP Credit.” According to Gerdau, a key benefit of Day-Ahead ELRP is the ability of Gerdau to provide demand response in a more predictable way while focusing on its core business rather than expending resources in real time to watch the price of energy consumed and determine if load reduction is beneficial.

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