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ELECTRICITY LAW DEVELOPMENTS – January 28, 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 November 2007 issue of Electricity Law Developments are **in bold**.

I. FERC PROCEEDINGS

A. On Rehearing, FERC Makes Little Change to Order 890 Docket Nos. RM05-17, RM05-25

On December 28, 2007, FERC issued an order on rehearing largely affirming Order No. 890, which dealt with changes to FERC's Open Access Transmission rules. Order 890-A, 121 FERC ¶61,297. Among issues addressed in the lengthy rehearing order, FERC responded to challenges by NRECA and other commenters questioning FERC's decision to revoke market based rate authority following an OATT violation only where FERC finds a specific factual nexus between the violation and the authority to charge market based rates. NRECA also questioned what might constitute a factual nexus and suggested that FERC revoke an entity's MBR authority whenever there is any violation of the transmission provider's tariff that denies a customer access to nondiscriminatory transmission services. In response, FERC disagreed that any material OATT violation would justify revocation of an entity's MBR authority because a violation may have no relation to the MBR authority. In such circumstances, FERC stated that it would consider other sanctions that it finds appropriate.

With respect to available transmission capacity (ATC), FERC clarified that transmission providers will be able to retain some discretion with ATC calculations provided that there is industry-wide consistency regarding ATC components. Order 890-A also affirmed FERC's decision to lift the price cap on reassignments of transmission capacity, but limited the time period during which reassignments may occur above the cap.

Finally, Order 890-A affirmed (and in some cases clarified) FERC's position with regard to:

- **Implementation of open and coordinated transmission planning;**
- **Standardization of energy and generation imbalance charges;**
- **Implementation of conditional firm and planning re-dispatch options for long-term point-to-point customers;**
- **Reform of rollover rights; and**
- **Rules regarding the designation of network resources.**

Several parties including Duke Energy and East Texas Cooperatives, have filed for rehearing.

B. FERC ANOPR on Reforms to the Organized Markets -- Docket Nos. RM07-19, AD07-7

ELCON joined a coalition of 41 signatories in filing a petition on December 17, 2007 asking FERC to expand the scope of the anticipated rulemaking proceeding on possible reforms to the organized markets to comprehensively investigate the justness and reasonableness of wholesale power supply prices in centralized markets administered by Regional Transmission Organizations. The coalition asserted that FERC's ANOPR on organized markets, which focused on demand response, long-term power contracting, market monitoring in the RTOs, and customer responsiveness in RTOs and ISOs, is not broad enough to address systemic problems in RTO markets that warrant immediate attention. The petition requests that FERC initiate a Section 206 proceeding to investigate, among other things, the potential exercise of market power by vertically integrated generators in RTO markets who are earning "supra-competitive returns that are not commensurate with returns on investments in other enterprises having corresponding risks." Record profits are reaped by selling power at market clearing prices well above cost, new investment and supply does not appear to be flowing into in RTO regions, and

rates consumers are paying in RTO regions are higher and increasing faster than in regulated markets.

History of the proceeding:

On June 22, 2007, FERC announced an Advanced Notice of Proposed Rulemaking (ANOPR) to initiate certain reforms of the organized markets. "Wholesale Competition in Regions with Organized Markets," 119 FERC ¶ 61,306. Some of FERC's proposals include:

(1) Demand Response and Pricing During Power Shortages

- Require RTOs and ISOs to allow demand resources to provide certain ancillary services in their markets unless not permitted by state law, modify tariffs to let demand resources provide spinning and supplemental reserves without being required to sell into the energy market.

- Modify RTO and ISO tariffs to eliminate certain charges for purchasing less energy in real time than in the day ahead market during a system emergency.

- Amend market rules to permit an entity that aggregates the demand responses of individual retail consumers to bid the aggregate demand reduction directly into an RTO or ISO energy market, unless not permitted by state law.

- Modify market power mitigation rules so that pricing during an emergency can elicit more demand response.

(2) Long-Term Power Contracting

- Require RTOs and ISOs to post information that would facilitate long-term contracts.

- Require or encourage efforts by RTOs and ISOs to develop standardized forward products.

- Dedicate a portion of the ISO's or RTO's website for market participants to post long-term buy/sell offers.

(3) Market Monitoring Policies and Information Sharing

- Remove the market monitoring unit from RTO/ISO operations.

- Require that the MMU advise the Commission and other stakeholders of any design flaws and report to the Commission any tariff violations it believes may have been committed by the RTO or ISO.

- Regular conference calls among the market monitor, interested state commission and FERC staff.
- Release of offer and bid data, with a lag period. Release would mask market participants' identities.
- Subject to certain limitations, state regulatory commissions within an RTO or ISO may request and receive information from the RTO's or ISO's market monitoring unit.
- Develop a pro forma tariff provision to address all sections relating to market monitoring.

(4) Responsiveness of RTOs and ISOs

- Provide RTO and ISO customers with direct access to the board of directors.

Recent Developments:

Several groups have subsequently filed comments, some supporting and some criticizing the petition, including the Electric Power Supply Association ("EPSA"), COMPETE, and PJM Industrial Customer Coalition ("PJMICC").

EPSA's comments (largely echoed by a filing by COMPETE and 81 other signatories) assert that the petition presents "only repetitious comments with no new information or proposals." EPSA argues that the four areas of inquiry outlined in the ANOPR adequately address petitioner's concerns. For instance, writes EPSA, demand response reforms leading to clearer price signals would contribute to the success of the market. EPSA also devotes considerable effort disputing the validity of concerns over market prices. In response to the petition's observation that electricity prices have appeared higher in certain RTO regions than in non-RTO regions, EPSA claims that nationwide price increases reflect rising fuel prices and costs associated with the risks of potential future environmental controls. EPSA argues that if RTOs were causing higher prices, "one would not see the electricity price increases outside of RTOs which are in fact

occurring, nor would prices have decreased by double digit percentages in every RTO/ISO from 2005 to 2006."

Another theme in EPSA's comments is that expansion of the FERC proceeding "would open a sweeping, open-ended process that would perpetuate the regulatory uncertainty that significantly impedes investment, at a time when by all accounts the electricity sector needs substantial new investment." Such a review would raise in the minds of investors the "specter of 'moving goalposts'" rather than presenting "clear rules of the road." EPSA also points to recent infrastructure improvements in RTO regions, including capacity expansions in the New England and PJM markets, noting that PJM's capacity market has led to the addition of over 3,600 MW of available capacity through 2010.

By contrast, the PJM Industrial Customer Coalition ("PJMICC") joined several other groups including Portland Cement Association, Multiple Intervenors, the Connecticut Industrial Energy Consumers, Industrial Energy Users-Ohio, and Mittal Steel USA, in voicing support for the petition, propose an alternative market design framework in the form of a Forward Capacity and Energy Market. While they note that the proposal may be appropriate only in regions that have in place a centralized capacity procurement approach, they suggest that such a Forward Capacity Energy Market would obtain the lowest-cost combination of capacity and energy payments while at the same time providing generators both a full return on capital investments and revenues sufficient to meet variable energy costs.

FERC is expected to issue a NOPR in connection with this proceeding.

C. FERC Affirms Inclusion of Two Florida QFs in NERC Compliance Registry while NERC Approves Removal of Two Others (FERC Docket Nos. RC07-3, RC07-5, C07-1-000, RC07-2-000)

On November 15, 2007, FERC affirmed two decisions by NERC and the Florida Reliability Coordinating Council (FRCC) regarding the inclusion of two QF cogeneration facilities in the NERC Compliance Registry. The cases involve situations in which more than one generating unit is on site and/or a radial transmission line interconnects the facility to the grid. In one case (Lee County Waste Energy Facility), the site has a 39-MW unit and a 20-MW unit. The facility is connected to the grid at a 138-kV substation. The second case (Solid Waste Authority of Palm Beach County) involves a single 73-MW facility interconnected at 138 kV. Both facilities were registered in the NERC Compliance Registry by FRCC, which NERC affirmed on appeal.

As the key consideration, the FERC orders reference the interconnection voltage, not the gross nameplate rating of the facilities or the amount of power put to the grid under a PURPA contract. Both facilities were interconnected at 138 kV, which exceeds the 100 kV threshold in NERC's Registration Criteria. The facilities argued that the NERC criteria exempt interconnections that are radial lines. FERC affirmed NERC and FRCC's interpretation of the "radial line" exemption as applying to radial lines that only serve load. Here, the lines are used to serve both load and generation. Both facilities had also argued that they should be exempt from registration because their QFs are below the 75-MVA size threshold for facilities with multiple generating units. FERC also rejected this argument, stating: "NERC's four criteria for the registration of generator owners and generator operators are written in the alternative, each connected by 'or,' so that an entity that satisfies any one of the four criteria should be registered." Because both facilities

exceed the size threshold for a single generating units, registration under NERC's criteria is appropriate.

In a related matter, on November 14, 2007, NERC approved an FRCC decision to drop two other Florida QFs from the compliance registry. FRCC explained in its decision that it determined upon further review that the removal of 69 kV facilities below a *de minimis* generation threshold of 20 MVA presented an acceptable level of risk to reliability.

D. FERC Grants PURPA Relief to SPP Utilities Despite Supplier Protests of Insufficiently Competitive Market (FERC Docket No. QM07-5)

On January 22, 2008, FERC granted the requests of the Oklahoma Gas and Electric Company (OG&E) and two AEP subsidiaries (the Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO)), for relief from mandatory PURPA obligations. The simultaneously-filed application of Xcel Energy Services Inc. on behalf of Southwestern Public Service Company was denied. 122 FERC ¶61,048. A divided Commission found that OG&E and the AEP subsidiaries met the statutory standard for prospective relief from the requirement to enter into new contracts with QFs with a net capacity in excess of 20 MW. Existing contracts and obligations with respect to QFs with a net capacity of less than 20 MW remains unchanged by the decision. The decision denying relief to Xcel was unanimous.

History of the proceeding

On September 25, 2007, the SPP utilities filed a voluminous application to terminate their requirement to enter into new contracts or obligations with QFs under Section 210(m) of PURPA. In the filing, among other things, the utilities argue that SPP's markets are comparable

to the ERCOT markets, which FERC, in Order No. 688 found meet the criteria for establishment of a rebuttable presumption that QFs have nondiscriminatory access to those markets despite the absence of a Day 2 Market. A number of QFs, along with EPSA, have protested the utilities' assertion, maintaining that SPP's Day 1 market is not yet sufficiently competitive to justify lifting the PURPA requirements.

This was the first such application filed under Section 210(m) that involved a Day 1 RTO. The applicable criteria governing such applications are those specified in Section 210(m)(1)(B):

> (B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) 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-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market . . .

By regulation, FERC has determined that SPP satisfies Section (B)(i). 18 C.F.R. § 292.309(g). Thus, the only bases for challenge is to assert either that the applicants have not made a proper showing that there exist "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-time sales" or that the application does not include all of the information required by 18 C.F.R. § 292.310(d) (*e.g.*, information about transmission constraints and congestion, description of processes and practices for arranging for transmission service).

In their responses to SPP's application, several renewable suppliers and EPSA asserted that competitive sales opportunities in SPP are limited given that only the EIS

market is currently available to competitive suppliers, and procurement processes are not overseen by an independent entity, thus, there is no assurance of nondiscrimination.

In particular, renewable suppliers argued that the features of the ERCOT markets which FERC found compelling in Order No. 688 are nonexistent in SPP and sales opportunities are "vastly inferior" to those provided by ERCOT markets. For example, ERCOT has certified numerous REPs while within SPP franchised utilities are dominant and usually the only entities providing retail electric service, thus buyers available to QFs in SPP are extremely limited. FERC is urged also to consider the particular transmission constraints within the SPP region, as these "may impair a particular QF's ability to access otherwise competitive wholesale markets."

According to the filings, the evidence of actual transactions filed by applicants falls short of the statutory requirements and suggests only minimal opportunities for QFs to sell energy and capacity to buyers other than utilities within SPP. It does not demonstrate the existence of the robust wholesale market applicants assert exists and does not meet the statutory requirements. The utilities identify only a single QF within SPP that makes sales into the balancing market. Furthermore, wholesale sales overall within SPP occur primarily on the margin. According to the data, the overwhelming majority of capacity and energy continues to be sourced from generation owned by the incumbent utilities. Moreover, SPP's real-time balancing market has been operating for less than a year, too brief a period to have had any meaningful impact on bilateral contracting opportunities.

With respect to competitive procurement, EPSA noted that no state requirements or standards for competitive procurement exist in three of the five states in SPP where the applicant utilities have assets or do business, and the other two states have been shown by

regulators and stakeholders to have serious flaws in the implementation of their procurement programs.

Recent developments

In its January 22, 2008 order, FERC found that QFs are faced with too many transmission constraints with respect to XCEL and therefore do not have meaningful opportunities to sell to other buyers. In approving the AEP and OG&E applications, however, FERC concluded that protesters had not provided QF-specific evidence of operational characteristics or transmission constraints within SPP's footprint that deny specific QF access to the markets:

> **[T]he evidence in the record shows that there is . . . active wholesale market activity in SPP, which provides QFs and potential and future QFs meaningful opportunity to sell their electric output to purchasers other than the interconnected utility. The number and types of transactions since 2004 indicate that there are competitive wholesale markets for both capacity and energy on both a long-term and short-term basis.**

Commissioner Sudeen Kelly issued a separate opinion stating that she agrees with the Commission's decision to deny XCEL's application, but strongly disagrees with the finding that the other applicants had satisfied their obligation to prove that QFs in SPP have nondiscriminatory 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-time sales to buyers other than the utility to which the QF is interconnected." According to Commissioner Kelly, both sides presented equally credible *prima facie* evidence and therefore:

> **the law dictates that Applicants' case must be dismissed for failure to satisfy their burden of proof. The decision maker (the Commission, in this case) cannot rationally prefer the Applicants' factual assertions over Protesters', or vice versa. To impute more credibility to one version of the facts than to**

another (without more process designed to determine which facts are more credible) is to act arbitrarily and capriciously.

Commissioner Wellinghoff also dissented in part from the decision on the basis that Applicants had not satisfied their burden of proof:

> **The filings before the Commission reflect parties' disagreement as to numerous issues of material fact. [For] example … [w]hile Applicants argue that EQR data supports their claims that the affected QFs have [a meaningful opportunity to make short-term sales], protestors argue that Applicants inappropriately ignore the Commission's market liquidity standard in examining the relevant short-term energy markets. The Commission would be well served by investigating this issue in a trial-type hearing.**

He further noted, however, that in light of the compressed time-frame in which FERC is to issue decisions on applications for PURPA relief, "it appears that the Congress did not intend for the Commission to use such procedures in these cases."

E. SPP Proposed Changes to Imbalance Market Challenged Docket No. ER08-242

On November 20, 2007, SPP asked FERC to approve a number of revisions to its OATT purportedly designed to improve the RTO's real-time Energy Imbalance Service (EIS) Market. In the filing, SPP indicated the proposed changes are based on experience gained in operating this market since its launch in February 2007. SPP stated that stakeholders had passed on the proposals.

On December 11, 2007, EPSA filed a protest arguing that certain aspects of the proposal will jeopardize the robustness of the EIS market and will "impede the ability and willingness of market participants to use the EIS" which is particularly problematic because the EIS is the only SPP market currently available for competitive suppliers to bid uncommitted generation. Under SPP's proposal, flows of imbalance energy will not be

assigned firm uninterruptible service. According to EPSA, "load will be unlikely to use the EIS if the imbalance energy it receives is always subject to interruption." This defeats the purpose of the EIS market, which is to afford efficient generation resources an opportunity to reliably displace less efficient generation. SPP's EIS market is in fact used for more than just imbalance energy. For example, an LSE is able to offer its own generation into the market, thus creating a negative imbalance for itself that in turn creates a corresponding opportunity in the EIS market for all resources to offer energy at lower prices to replace the LSE generation. "As such, the EIS provides a critical mechanism that can allow the SPP system to be dispatched in a efficient manner and ensure that load can be met using least cost available resources from competitive suppliers," said EPSA. SPP failed to provide any support for its assertion that the use of firm transmission service for imbalance energy is inappropriate, EPSA argued. At a minimum, the Commission should require the RTO to offer a better justification for the proposal than merely stating that stakeholders had expressed support.

On December 21, SPP filed a response to EPSA arguing that its proposal to designate unscheduled imbalance transactions as non-firm will not harm the EIS market , and that this is consistent with SPP's joint operating agreement with the Midwest ISO. SPP noted:

> **While EPSA is correct that market participants are free to use the EIS market for more than imbalance energy, being free to use the EIS market and being guaranteed that the EIS market transactions will be available at all times, especially in times of constraints on SPP's transmission system, are two separate issues. SPP does not believe it is reasonable to permit unscheduled imbalance energy to displace scheduled transactions using network transmission service from non-designated resources or compete with network and point-to-point transactions using firm transmission service. SPP's proposed revision thus ensures that network and point-to-point**

customers' transmission rights are protected from being improperly displaced by what is essentially unscheduled secondary network service.

SPP indicates that EIS flows which are properly scheduled may receive firm priority, though it does not explain how one would go about "properly scheduling" imbalance energy on its system.

FERC has not yet acted on this matter.

F. FERC Allows PJM ELRP "Subsidy" Program to Sunset (FERC Docket No. EL08-12)

In 2002, FERC approved PJM's Economic Load Response Program ("ELRP") on a temporary basis, and later allowed the program to become permanent. To encourage participation in the demand response program, under the ELRP, end-users were paid the real-time or day-ahead LMP for power usage they would curtail, less generation and transmission charges they would otherwise have incurred. However, if the market price for power exceeded $75/MWh, participants were paid the full LMP, inclusive of generation and transmission charges.

On November 20, 2007, the PJMICC filed a complaint arguing that to allow PJM's ELRP to expire as planned on December 31, 2007, would be unjust and unreasonable. Allowing the program to sunset would have the result that "all economic demand responders will be denied the opportunity to receive just and reasonable compensation for the benefits they bring to PJM by providing load curtailment." PJMICC argued that allowing the program to expire would be a violation of the FPA because the tariff provisions are necessary in some form to ensure at least minimal levels of demand elasticity in the market and thus, serve as one of several "checks" on the exercise of market power.

In a December 31, 2007 order, FERC declined to prevent the provisions from sunsetting. Characterizing the payments as a "subsidy," the majority explained that the payments were originally approved as an interim means to encourage participation in the new program in order to provide reimbursement for startup expenses. Now that the program has been in place for several years, it is not unreasonable "for the PJM stakeholders to conclude that customers interested in demand response have already had sufficient opportunity to recover start-up costs, so that a subsidy payment is no longer necessary to create an incentive to participate in the program." FERC also said that lapse of the subsidy does not mean PJM customers lack incentive to reduce load in response to appropriate wholesale price signals. Customers paying retail rates below the applicable wholesale rate will be paid the difference between wholesale and retail rates. For wholesale customers, "because these customers are paying the applicable wholesale price, they already have an incentive to curtail load."

Commissioner Kelly and Wellinghoff strenuously dissented, objecting to the majority's use of the term "subsidy". The expiring payments do not amount to a "subsidy" because, as PJM's own market monitor has found, the costs of the demand response program are greatly outweighed by the benefits, thus no subsidy is borne by other customers. Additionally, since LMP reflects market value of a resource, payment of the full LMP to demand response providers is comparable to LMP payments to generators. "By contrast, offsetting LMP by the demand response provider's 'avoided' retail rate ignores the fact that the load-serving entity . . . is avoiding generation and transmission costs that it would have incurred to serve the customer providing the demand response. Because those costs are avoided by both seller and customer, there is no 'subsidy' to

recover from other customers." They were also critical of the Commission's failure to take the opportunity to use the proceeding to develop a more complete record on what compensation is appropriate for demand response providers in the PJM market.

ELCON plans to join in PJMICC's request for rehearing.

G. PJM Stakeholders and Market Monitor Settle Dispute Docket No. EL07-56

On December 19, 2007, PJM, its market monitor and numerous of its stakeholders filed a settlement agreement with FERC addressing the dispute over the independence of its internal market monitor. According to the filing, all but one of the parties involved in the settlement negotiations have signed on or indicated no objection to the settlement. Under the agreement, an external MMU will be created headed by the grid operator's current external market monitor, with service to be provided by contract. The contract can only be terminated by FERC approval and at certain times and under certain outlined conditions. The MMU is to be independent from the direction, supervision, review or other interference in the execution of duties under the agreement, except that the PJM Board (defined to exclude any members of PJM management) has authority and responsibility to review the MMU's budget and to propose to terminate, retain by contract renewal, or replace the MMU in accordance with certain conditions outlined in the agreement. The PJM Board is also to meet and confer with the MMU from time to time on matters relevant to each entity's duties under the Market Monitoring Plan. Additionally, no entity will be able to preview, screen, alter, delete, or otherwise exercise editorial control over or delay the MMU's actions or investigations or the MMU's reports, findings, conclusions and recommendations.

The settlement agreement includes detailed rules and procedures to allow the MMU access to PJM's data and to ensure the MMU's ability to maintain sole control over information it gathers in connection with its contractual obligations. State commissions will be able to receive confidential information from PJM or the MMU provided they certify to FERC that they have adequate safeguards in place to prevent the information from release to unauthorized parties. Among the enumerated functions and obligations, the MMU shall objectively monitor the competitiveness of the PJM markets, investigate violations and recommend changes to market rules. The MMU is to investigate actual and potential exercises of market power or rule violations. The MMU is also to monitor PJM's implementation of market rules and operation of the markets and may advise PJM is if disagrees with any such implementation or operation. If a disagreement cannot be resolved informally, the MMU may bring the situation to the attention of the Commission. While PJM is responsible for proposing changes to PJM market design, the MMU may initiate and propose changes through appropriate stakeholder process if it detects design flaws or other problems with the PJM market. The MMU may recommend PJM take specific mitigation action, but may not modify operational decisions. If mitigation recommendations are not heeded, the MMU may, where appropriate, report the matter to PJM members, to FERC or to authorized government agencies.

The agreement also provides for the creation of an OPSI Advisory Committee, an MMU Advisory Committee (open to all stakeholders and relevant government agency representatives) and a PJM liaison (a PJM employee appointed to facilitate communications between PJM and the MMU).

If approved as filed, the revised market monitoring plan would be implemented beginning June 1, 2008.

H. California Rulemaking Proceeding on Resource Adequacy Requirements CPUC Docket No. R.05-12-013

There have been two important developments related to the California Public Utilities Commission ("CPUC") rulemaking to consider features of a resource adequacy requirements ("RAR") program, including capacity markets in California.

The Market Surveillance Committee ("MSC") of the California ISO ("CAISO") has advised CPUC to defer consideration of a centralized capacity market ("CCM") for at least a decade. In a November 5, 2007 opinion (available at www.caiso.com), MSC noted that it is not recommending against ever implementing a centralized capacity market; however, under the current California market structure, with major policy initiatives underway and significant unsettled issues, including uncertainty about performance of the new LMP market and day-ahead integrated forward market, debate over the future of retail choice and aggressive renewable energy and emissions policies, implementation of a centralized capacity market would be ineffective and costly.

MSC's opinion made a number of points in line with the comments that were filed by ELCON and the Bilateral Trading Group ("BTG"). The MSC found that between the Market Redesign and Technology Update ("MRTU") that CAISO is in the process of implementing and the evident problems with the eastern markets' capacity market structures including significant increases in wholesale energy and capacity costs related to implementation of the CCM mechanisms, it is "a singularly inappropriate time for California to commit to a new resource adequacy mechanism

with potentially significant cost consequences." MSC stated that it might support a centralized capacity market at a later time, if conditions and market features were such that a CCM would "fit the California market." However, at present,

> **in general, the long-run economic organization of the California market remains very much a moving target. Given the great degree of uncertainty and ongoing change currently at play in California, we feel that a far more prudent and cost-effective course of action at this point is to refine the current RA paradigm to correct known flaws rather than completely overhaul it, while preserving the option of a full redesign at a later date. Moreover, a number of potential problems with the current RA paradigm may be addressed by MRTU. As the MRTU implementation process identifies the need for new energy and ancillary service products, new RA needs may be identified. A number of the eastern ISOs are currently in the initial stages of implementing new long-term capacity payment mechanisms in response to perceived shortcomings in their former capacity payment mechanisms. Another market, Texas, is pursuing the so-called "energy only" path. By delaying significant changes in its RA paradigm, California can learn from the experience of these ISOs.**

In short, the MSC summarized, there is substantial value to deferring any major overhauls of the Resource Adequacy structure until California's specific needs for such a product "are known with greater clarity."

On January 18, 2008, however, the CPUC Energy Division staff issued a report summarizing their recommendations on a capacity market structure. They note that no individual proposal put forth by parties entirely satisfies the CPUC's goals without modification. However, they utilized the BTG proposal and the proposal advocated by a consortium of IOUs and generators for a Centralized Forward Capacity Market (CFCM), though markedly different from one another, as the basis for two alternative staff-approved recommendations, each representing "distinct policy directions that are best made at the Commissioner level."

The first recommendation is for a "Modified Centralized Market" ("MCM"). This recommendation incorporates aspects of the centralized forward capacity market, the CAISO's centralized capacity market proposal and PG&E's composite proposal. The MCM is a bifurcated capacity market, the staff explain, that recognizes there are multiple goals for a resource adequacy program that utilizes capacity as an element in determining and ensuring the adequacy of resources.

> **The first element of the MCM is the Preliminary Capacity Showing (PCS) which occurs in a more that four year forward environment. The PCS requires IOUs to bilaterally procure a percentage of their forecast peak load in advance of the centralized market. New Generation is incorporated in the PCS only as directed by the CPUC for Renewable Portfolio Standard (RPS) and other Long Term Procurement Planning (LTPP) purposes unless it is determined to be less expensive than existing capacity. The showing is generally consistent with the current RA program except that the capacity product is standardized under a CAISO tariff and the product is seasonal rather than monthly.**
>
> **The second element of the MCM, the Centralized Forward Reliability Market (CFRM), is a multi-year forward CCM for the remaining forecast load as well as planning and operating reserves. …[LSEs] with significantly large purchasing power are required to remain exposed to the market clearing price for five percent of their forecast load. All capacity that participates in the CFRM is responsible for a Peak Energy Rent …deduction that is calculated on an ex post basis based on a marginal inefficient unit. The CFRM also includes reconfiguration auctions that enable adjustments to capacity positions to accommodate load migration or other market changes.**

The second recommendation is based on the BTG proposal and entails modifications to the existing RA program. The proposals include an electronic bulletin board to increase pricing transparency, a standardized capacity product and an opt-out mechanism from backstop procurement. The program would consist of LSE-based bilateral procurement of capacity in a short-term environments and new capacity entering the market via IOU procurement with a cost allocation mechanism.

Irrespective of which program the CPUC ultimately adopts, the staff recommend several changes from the current RA program, including a seasonal capacity product, and ex post calculation of Peak Energy Rent deduction that is locally variable, and participation by demand response.

The CPUC staff's report "Track 2 Report on Staff Recommendations for Capacity Market Structure" is available on the CPUC's website at ftp://ftp.cpuc.ca.gov/puc/hottopics/1energy/r0512013MarketStructure.PDF.

I. FERC's Generation Interconnection Rules Challenged on Various Fronts (Docket Nos. RM02-1, AD08-2)

On December 11, 2007, FERC held a technical conference to explore possible reforms to unforeseen problems with the generation interconnection rules contained in its July 2003 Order No. 2003 regarding standardization of generator interconnection agreements and procedures. 104 FERC ¶61,103.

In particular, FERC noted problems with queue management systems that have resulted in a tremendous backlog of projects waiting to interconnect in certain regions of the country. The problem appears to be particularly acute with respect to wind energy projects. Project developers in the organized markets have requested interconnection for more than 100,000 MW of new wind generation project, most of which will never be built, but which clog the queues and delay interconnections for real projects. During the conference, it was noted that transmission providers are unable to distinguish between the "phantom" projects and the real projects and have no enforceable time frame in which to complete interconnection processes.

Another problem identified is uncertainty about interconnection costs and how new transmission upgrade costs should be allocated. The American Wind Energy Association indicated that from the point of view of small renewable projects, this is better handled in non-RTO areas where charges are not paid through participant funding, but rather are "socialized." "Participant funding," they said, "creates a situation where a typical 100-MW, $200 million wind project might face a network upgrade charge of $0 to $30 million with little basis for knowing where in that large range the price tag might fall."

MISO and the Midwest Transmission Owners ("MISO") submitted comments in response to a question raised by FERC staff during the technical conference -- to what extent are the problems with the interconnection queue simply local interconnection problems and to what extent are the problems caused by a lack of available transmission capacity? According to MISO, in recent history connection difficulties have been more often related to broader export issues. "Without backbone planning, which incorporates long-term energy delivery needs, the queue backlogs can be expected to continue, as it will remain a complex and time-consuming task to integrate new generation both from a physical and economic perspective" they note. They gave the example of a proliferation of wind projects that has occurred in the MISO region in areas that have a low load density. Planned upgrades to that area will increase the export capability of that region to approximately 2000 MW in 2014; however, there are currently 22,000 MW of requests proposed for that region. They explain that on the periphery of this electrical area, there may be locations where the immediate interconnection facilities are robust enough to accommodate a particular request. However, once those electrons flow past the interconnection facilities, they try to flow with other electrons from other queued

generators and the transmission lines simply cannot handle the strain. This problem is exacerbated by the distinction between Energy Only and Network Resources in a market environment. These Energy Resources have the right to interconnect and inject their power into the grid, but there is no requirement to have that power taken off the grid at any particular point.

Among possible solutions that were discussed during the conference are reforms to engineering study procedures, establishing enforceable interconnection timetables and enforceable milestones for projects that wish to remain in the queue, and increasing the price a developer pays to reserve a position on the interconnection queue. One FERC commissioner suggested FERC consider an electric transmission "open season" comparable to that used with natural gas pipelines; however state regulators expressed skepticism, noting it likely would run into jurisdictional hurdles because unlike natural gas pipelines which are exclusively within FERC's jurisdiction, electric transmission lines can be subject to multiple states' jurisdictions.

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 American Forest & Paper Association 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 Cogeneration Association of California,

On November 6, 2007, the Court granted ELCON's motion to participate as *amicus curie* in support of AF&PA. ELCON will seek to address FERC's poor rationale for finding the existence of long-term markets, and may raise other issues that it had raised in the proceeding before FERC. The D.C. Circuit has not yet set a schedule for briefing or oral argument.

B. FERC Reverses Stance on *Mobile-Sierra* Again in Brief to Supreme Court in *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County* (Case Nos. 06-1457, 06-1462)

Briefing is underway in the Supreme Court's review of the appellate court decisions on *Mobile-Sierra*, Public Utility District No. 1 of Snohomish County v. FERC and California Public Utility Commission v. FERC. In those cases, the Ninth Circuit took FERC to task and overturned its decisions upholding onerous long-term power contracts entered into by California entities and private utility buyers at the time of the California energy crisis in 2001. FERC had upheld these contracts based on the *Mobile-Sierra* doctrine, which refers to two 1956 Supreme Court decisions and generally precludes FERC from re-opening the contracted-for rates in long-term contracts unless required by the *public interest*. The court ruled that FERC improperly sought to apply *Mobile-Sierra* despite pervasive evidence of dysfunctional markets, market power and market manipulation. Instead, FERC should have assessed whether the rates were "just and reasonable."

FERC had earlier expressed willingness to accept the Ninth Circuit's decisions, but following the appeal by private parties in the case found it necessary to defend its original order to the Supreme Court. In its brief, FERC argued that: (1) the Mobile-Sierra doctrine's protection against reopening of contractual terms is equally applicable to a high

rate or a low rate case -- since both buyers and sellers can make bargains that in hindsight they would like to undo, both buyers and sellers need the Commission's protection from counterparties seeking to undue bad deals; (2) the Ninth Circuit should have deferred to the expertise of the administrative agency under the *Chevron* doctrine; (3) the Ninth Circuit's stated prerequisite to applying the *Mobile-Sierra* doctrine -- that FERC must provide "sufficient oversight for contracts made under market-based rate authority to ensure that the resulting rates were within the statutory 'just and reasonable' range in the first instance" – is an "unwarranted intrusion into the agency's judgments about how to adjust its regulatory scheme to account for market-based rates . . ."; and (4) "[n]ot every instance of market power, manipulation, or dysfunction will merit contract abrogation."

A group of economists filed a brief supporting FERC. "Long term contracts, in particular" they noted, "help reduce financial risk. Those contracts can only accomplish that goal, however, if parties know the contracts will be enforced." Particularly in the energy industry, fluctuating input and sales prices can best be dealt with through stable, long-term contracts, they argued. In addition, the economists noted that infrastructure development would be hampered by the Ninth Circuit's contract abrogation, because electricity producers "will not invest the extraordinary resources needed to develop new energy sources without some assurance that they will recoup their investment." The economists also argued that volatile markets uniquely call for contract certainty: "[l]ong-term contracts are a *remedy* for crisis conditions because they allow buyers to reduce the risk posed by extreme volatility in spot markets." They reasoned that long-term contracts allow market participants to allocate the risks that result from an incomplete picture of the market at any point in time. That being the case, neither the fact that the contract rates

seem unreasonable *after* the unknown information become known, nor the fact that the contracts were negotiated amid highly volatile prices, should justify interference in the parties' attempts to manage future price risks caused by a volatile market.

The International Swaps and Derivatives Association and the Financial Institutions Energy Group ("ISDA") argued in their separate brief that "in a regulatory system built on a foundation of private contracts, the starting presumption . . . is that the 'just and reasonable' rate *is* the contract rate." ISDA also emphasized a distinction between the dysfunctional spot market, which was directly disrupted by illegal conduct, and the forward markets, in which prices were high but no illegal activity was found. ISDA argued that courts should not interfere with long-term contracts because, even if the short-term market prices were bid up by illegal activity, it is still desirable for parties to be able to turn to long-term contracts to both minimize the harm and risk caused by short term fluctuations, and to create an incentive to alleviate shortages by offering higher long-term prices that would encourage building new generation capacity.

The Electric Power Supply Association ("EPSA") and companion groups emphasized in their brief that the courts should recognize FERC's and Congress's conclusion that "' [I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable' and in the public interest."

In its brief supporting the Ninth Circuit decision, Snohomish asserted that: (1) a proper re-reading of the Mobile and Sierra cases does not support a standard of review for contracts that differs from the "just and reasonable" standard of the FPA; (2) for the contracts at issue in this case, FERC did not provide "a timely opportunity to review

rates," which Congress "deemed as essential . . . for producing just and reasonable rates;" an after-the-fact filing is not sufficient where there is no effective monitoring, as was the case during the Western energy crisis; (3) arguments that the Ninth Circuit impacts the sanctity of contracts "should be addressed to Congress, which enacted a statute that requires rates to be just and reasonable and directs FERC to correct rates that are not," rather than the courts; (4) "FERC cannot in the name of contract stability enforce contracts that are unjust and unreasonable;" and (5) reformation of contracts in this case would improve the function of the energy market because investment based on false price signals could cause a "boom-and-bust investment cycle" and because buyers will likely be deterred from entering into long-term contracts when they have reason to fear that market abuses will not be forcefully corrected, noting that the "market manipulation and gaming of the new deregulatory system in 2000-2001 went far beyond ordinary supply-demand dynamics."

Co-respondents Public Utilities Commission of the State of California and California Electricity Oversight Board ("PUC") emphasized that "the FPA requires at least one opportunity for a determination whether the rates in the subject contracts were just and reasonable" when signed, and that "neither the signing of the contracts nor the *ex ante* grant of market based rate authority to the sellers provides an adequate substitute for such an opportunity." PUC asserted that the initial grant of market-based rate authority cannot support a conclusion that the rate was reasonable at the time of contracting, because there is no consideration of market conditions at that time. Additionally, PUC argued that FERC's determination that the forward markets were functioning does not guarantee that prices were just and reasonable; even absent specific price manipulation in

the forward markets, the price manipulation of the spot markets could easily have resulted in forward prices that were unjustly and unreasonably high. PUC concluded that because the majority of electricity transactions in the U.S. occur through bilateral, private contracts, FERC's position would effectively carve out the bulk of the electricity market from rate regulation protection for consumers.

Oral argument is scheduled for February 19.

C. Ninth Circuit Rejects Retail Ratepayer Suit to Recover Damages From Market Manipulation During Western Energy Crisis (507 F.3d 1222 (9th Cir. 2007))

On November 20, 2007 the Ninth Circuit ruled in a 2-1 decision that a retail ratepayer could not seek damages in federal courts under the filed-rate doctrine. Wah Chang, an Oregon chemical manufacturer, filed suit in the U.S. District Court for the Southern District of California seeking refunds from Duke Energy Trading and other power sellers. Wah Chang's case differed from previous suits seeking refunds from wholesale market price manipulation in that Wah Chang did not contract directly with any wholesale sellers. Rather, Wah Chang purchased power at retail from PacifiCorp, which in turn purchased power on the wholesale spot market. Wah Chang's rates under its purchase contract with PacifiCorp were indexed to the wholesale market, however, and so the retail rates it paid soared along with the wholesale market rates due to market manipulation.

The majority on the Ninth Circuit was unimpressed with the distinction. They reasoned that Wah Chang's suit still effectively asked the federal courts to determine the rates that power sellers should have charged during the 2000-2001 period. Such a

determination would not be allowed under the filed-rate doctrine, which protects the rate setting authority of federal agencies from after-the-fact court challenges; rather, petitioner's sole recourse was a rate challenge before FERC. The dissenting judge questioned whether the retail ratepayer is now completely shut out from any recovery.

D. Petition for Review of FERC's Order on MISO's Ancillary Services Market Proposal (U.S. Court of Appeals for the Seventh Circuit, Case No. 07-3592)

On October 26, 2007, the MISO industrials (Coalition of Midwest Transmission Customers or "CMTC") filed a petition for review with the Seventh Circuit of FERC's orders regarding MISO's proposed implementation of day-ahead and real-time ancillary service markets ("ASM"). The court's decision could have significant precedential effect on FERC's implementation of market-based rate authority beyond the MISO proceeding at issue.

In the underlying FERC proceeding (Docket No. ER07-550), the Commission issued an order rejecting, without prejudice, MISO's ASM proposal, in part because MISO had not submitted a market power analysis and had not submitted a sufficient readiness plan or otherwise developed adequate safeguards for the transition to operation of a centralized ASM. However, as MISO had interpreted the order as approving the key concepts of its ASM proposal, CMTC filed a petition for rehearing, which FERC denied. CMTC states that the central issue to be presented to the Court is "whether FERC must find that a market is competitive before authorizing sales into that market at market-based rates." Regarding this issue, FERC held:

> The Commission rejects MISO Industrial Customers' argument that, as a prerequisite to reliance upon market-based rate pricing to produce just and reasonable rates, the Commission must, in addition to finding that applicants lack or have adequately mitigated market power, make a separate and independent finding that a competitive market exists. In the Commission's recent market-based rate rulemaking, commenters raised these same general arguments. We therefore incorporate by reference the Commission's discussion in its final rule on market-based rates (Order No. 697) of the legality of its approach to market-based rates. The Commission's long-established

> approach involves assessing whether a seller lacks market power, which includes an assessment of seller-specific market power. This approach, combined with the Commission's filing requirements and ongoing monitoring, allows the Commission to ensure that market-based rates remain just and reasonable. Additionally, for sellers in RTO/ISO organized markets, the Commission has in place market monitoring and mitigation rules to mitigate the exercise of market power, including price caps where appropriate, and the Commission also uses RTO/ISO market monitors to help oversee market behavior and market conditions.
>
> MISO Industrial Customers have read a "separate and independent finding" requirement into precedent where it does not exist. Indeed, the Commission has never imposed such a requirement and MISO Industrial Customers provide no justification for doing so in this proceeding. Moreover, no court has taken exception to the Commission's approach of focusing on applicants' market power in determining whether to approve market-based rate pricing.

120 FERC ¶ 61,202 Paras. 9-10 (Aug. 30, 2007 Order Denying Rehearing; footnotes omitted).

MISO, Indianapolis Power & Light Company, Reliant Energy, the Wisconsin Public Service Corporation, Integrys Energy Group, Inc., and Wisconsin Electric Power Company have intervened in the case. The schedule for briefing and oral argument has not yet been established.

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