

# CLEARY GOTTlieb STEEN & HAMILTON LLP

2000 PENNSYLVANIA AVENUE, N.W.  
WASHINGTON, D.C. 20006-1801  
(202) 974-1500

## **ELECTRICITY LAW DEVELOPMENTS – February 2, 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. New inside this issue:

- Following court ruling striking down provisions governing behavior between natural gas pipelines and their energy affiliates, FERC announces new standards of conduct rulemaking (p.2)
- FERC utilizes expanded penalty authority under EPACT 2005 for first time (p.5)
- SPP finally allowed to launch energy imbalance market (p.7)
- Numerous rehearing requests filed in response to conditions imposed by FERC on PJM reliability pricing settlement (p.7)
- FERC issues order eliminating peaking unit safe harbor mechanism in ISO-NE (p.17)
- ELCON intervenes in California Public Utilities Commission rulemaking on resource adequacy and capacity markets (p.19)

New developments since the January 11, 2007 issue of Electricity Law Developments are in **bold**.

## **I. FERC PROCEEDINGS**

### **A. Standards Of Conduct Rulemaking FERC Docket No. RM07-1**

---

Recently the U.S. Court of Appeals for the D.C. Circuit issued a decision in National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (2006), striking Order No. 2004, the rule that imposed standards of conduct on gas pipelines and their energy affiliates. The court stated that FERC “has provided no evidence of a real problem: and failed to identify “a single example of abuse by non-marketing affiliates.” Rather, the only instances of abuse relate to *marketing* affiliates. As a consequence of the decision, on January 9, 2007, FERC issued an interim rule with a new provision stating that the standards of conduct do not govern the relationship between gas transmission providers and their energy (as opposed to marketing) affiliates. 18 CFR 358.1(e). On January 18, 2007, FERC issued a NOPR proposing to make permanent the interim regulations and requesting comments on the application of standards of conduct to energy affiliates of electric utilities and on various other changes to the standards of conduct.

As a threshold matter, there are several larger implications to the D.C. Circuit decision. The court ruled that FERC must justify its regulatory action by evidence to assure that regulatory burdens that it imposes are not arbitrary and capricious. The court noted that there is strong theoretical basis for application of the standards to non-marketing energy affiliates – there is no policy against vertical integration. A perhaps unintended consequence of the decision will be that FERC will look for evidence to document proposed regulatory actions—not only in the context of revising its standard of

conduct rules but on issues like addressing transmission discrimination. FERC does not specify what is meant by evidence (e.g., informal or formal evidence of abuse). However, increased attention to “evidence” as a predicate for FERC rules is a development whose consequences are difficult to predict.

In light of the D.C. Circuit’s decision, in the January 18 NOPR FERC notes that prior to issuance of Order No. 2004, standards of conduct prohibited gas and electric transmission providers from favoring their *marketing affiliates* by imposing a separation of functions and prohibitions on information sharing. (See Orders Nos. 497-gas and 889-electric utilities.) After FERC decided in Order No. 2004 to broaden the standards to relationships between these utilities and energy affiliates, only the gas pipelines appealed. While the D.C. Circuit decision addresses only gas, FERC suggests that its rationale applies to electricity as well: in neither context can the rule be sustained if there is no evidence of abuse between utilities and their non–marketing affiliates.

Commenters who advocate that it is appropriate for the standards of conduct to include energy affiliates are directed to “submit evidence” to support this result. Categories of energy affiliates listed by FERC includes a) affiliated asset managers, b) affiliated transmission customers that do not make sales for resale, c) affiliated gas entities such as producers, gatherers, LDCs, and intrastate pipelines, d) affiliated financial institutions that engage in financial transactions, e) affiliates that aggregate and resell transmission capacity without making sales for resales of energy, f) affiliated electric LDCs, g) affiliated electronic trading platforms, and h) affiliated entities that buy trade, or administer electric energy.

FERC notes that past complaints of utility abuse relate to preference for the

**transmission provider’s *merchant function*. FERC states that the definition of marketing affiliate covers an electric transmission owning utility’s merchant function and proposes to retain this “important protection.” FERC reaffirms that it “will continue to be unlawful for electric utility providers to provide any undue preference to their merchant function or any affiliate that owns generation or sells electricity.” FERC proposes to expand the definition of marketing, sales or brokering to include asset managers that are involved in transmission scheduling and similar functions. FERC notes its recent investigations resulting in fines paid by AEP, CLECO, and a settlement reached with SCEG.**

**FERC also seeks comment on (i) modifying the standards of conduct to allow new categories of employees, those engaged in either IRP or in competitive solicitation, to access non public transmission information and to interact with transmission function employees, (ii) whether the new categories of planning and competitive solicitation employees should be limited to bundled retail load or instead should be broadened to include other loads, (iii) adopting provisions regarding permissibly shared risk management employees, (iv) requiring the posting of a log of a transmission provider’s discretionary acts, and (v) requiring transmission providers to post the name of their chief compliance officer and to certify completion of standards of conduct training.**

**The fundamental issue on which the Commission has requested comment is whether there is factual evidence that the eight categories of energy affiliates identified above have engaged in abuse in electricity, or at least a “strong theoretical basis” for a conclusion that such abuse is likely to occur. Absent such evidence in the record, the D.C. Circuit determination that the Commission cannot impede vertical integration without adequate**

justification would dictate that FERC limit the standards of conduct in electricity to marketing affiliates, just as it has done for gas.

Comments are due March 30, 2007.

**B. First Penalties Imposed by FERC Under EPACT 2005 Authority  
FERC Docket Nos. IN07-1, IN07-3, IN07-4, IN07-5, IN07-6**

On January 18, 2007, FERC for the first time used its expanded civil penalty authority under EPACT 2005. EPACT 2005 gave the Commission power to assess civil penalties of up to \$1 million per day of violation of rules, regulations and orders pursuant to the FPA, NGA and Natural Gas Policy Act. FERC approved five settlements of enforcement matters, assessing civil penalties totaling \$22.5 million. Four of the settlements (SCANA Corp., PacificCorp, Entergy Corp., and NRG Energy Inc.) involved self-reporting of violations of tariffs, rules and standards of conduct. The fifth settlement (Northwestern Energy Corp.) involved violations of the company's tariff and the Commission's Business Practice Standards.

None of the settlements imposes maximum penalties, but rather were based on an application of factors outlined in its Enforcement Policy Statement (113 FERC ¶61,068, October 20, 2005). The Commission cautioned in a press release that going forward, it will seek maximum penalties "where they are called for by application of these factors, such as when the harm caused by the violation is very significant, where there is complicity of senior corporate management, or the company obstructed our investigation." None of these factors reportedly were involved in the January 18 settlements.

A FERC press release dated January 18, 2007 describes the settlements:

**SCANA CORP:** SCANA agreed to pay a \$9 million civil penalty and to disgorge \$1.4 million in profits to resolve an investigation into violations of the utility's OATT. Specifically, FERC staff identified more than 1000 transactions during a four-year period in which South Carolina Electric & Gas, a SCANA subsidiary, improperly used network transmission to facilitate off-system wholesale power sales in violation of its OATT.

**PACIFICORP:** PacifiCorp agreed to pay a \$10 million civil penalty to settle violations of the utility's OATT and Standards of Conduct. Staff's investigation found that PacifiCorp engaged in hundreds of OATT violations granting undue preference to its merchant power function, and engaged in numerous and significant Standards of Conduct violations. Specifically, following its acquisition by MidAmerican Energy Co., PacifiCorp self-reported having used network transmission service for transactions that should have employed point-to-point transmission service. FERC staff identified 1,096 violations since April 2003, representing 174,639 megawatts of total transmission service. The violations occurred under PacifiCorp's prior ownership. Reportedly, the new owner has taken steps to ensure that there will be no recurrence of these violations, including retention of an independent auditor to review and report on PacifiCorp's compliance with its OATT.

**ENTERGY CORP.:** Entergy agreed to pay a \$2 million civil penalty and to contribute \$1 million to a hurricane relief fund to settle three separate self-reported matters: (1) Employees of Entergy lost, in violation of the Federal Power Act, all hourly Alternative Flowgate Capability (AFC) data files from the start of the AFC system in April 2004 through January 2005; (2) Entergy's AFC system responded in error to nearly 2,000 requests for transmission service between April 2004 and January 2006; and (3) Entergy on multiple occasions failed to post information on its OASIS in violation of the Commission's OASIS posting requirements. In addition to the civil penalty, Entergy agreed to a substantial compliance plan tied to the new Independent Coordinator of Transmission approach to Entergy's transmission system operations. The plan includes a number of reporting, auditing and training elements.

**NORTHWESTERN ENERGY:** Northwestern agreed to pay a \$1 million civil penalty to settle 83 instances in which the utility violated its OATT, including failure to act on requests for firm monthly and yearly point-to-point transmission service within 30 days, as required by the Commission's Business Practice Standards.

**NRG ENERGY:** NRG agreed to pay a \$500,000 civil penalty to settle violations of Commission Market Behavior Rules that resulted from the misrepresentation of a reliability-must-run generation facility in ISO-New England. Staff found that NRG intentionally misrepresented that the generating plant was available, when it was not. The misrepresentation resulted from the actions of a single employee and did not involve NRG senior management, the staff investigation concluded. NRG took immediate corrective action, including reporting the incident to the Commission

**and ISO-New England.**

**FERC reports that it has received more than 40 self-reports since August 8, 2005, the date the Energy Policy Act took effect, mostly for violations that did not merit civil penalties.**

**C. FERC Finally Allows SPP Launch of Real Time Energy Imbalance Market  
FERC Docket No. ER06-451**

---

**On January 26, 2007, FERC gave SPP the go ahead to launch its energy imbalance market on February 1, 2007 despite lingering doubts expressed by several market participants that the market had been adequately tested.**

SPP received FERC approval as an RTO in October of 2004 (109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005)). At that time, FERC accepted SPP's commitment to develop an imbalance market, including implementation of a real-time, offer-based energy market that will be used to calculate the price of imbalance energy. The Commission also required SPP to provide a market monitoring plan, including market power mitigation measures that address market power problems in the spot market and a clear set of rules governing market participation conduct, with the consequences for violations clearly laid out. FERC had rejected SPP's original imbalance market proposal and mitigation and monitoring plan as inadequate and provided guidance concerning: (1) reliable and stable market operations; (2) market-based rates in the new market; and (3) mitigation and monitoring issues. 112 FERC ¶ 61,303(2005).

In March 2006, FERC had rejected in part and conditionally accepted and suspended in other parts SPP's proposed revisions to its OATT related to its proposed real time energy imbalance market and market monitoring plan, indicating that based on experience, it was

reluctant to approve an incomplete plan. FERC had found that the proposed tariff provisions require modification or elaboration before it would be able to determine whether the imbalance market was designed and monitored properly. In particular, as acknowledged by SPP in its filing, the plan lacked certain key elements including an external market monitor contract, new provisions for transmission loss compensation, standard market participant and reserve sharing agreement, and a plan to measure market readiness performance.

**In May 2006, SPP had submitted for FERC approval an Offer of Settlement between SPP and its balancing authorities detailing the division of functional responsibilities. In November, FERC conditionally accepted the settlement, but again requested clarification of certain provisions. SPP made a further compliance filing on December 15, 2006, and on December 22 filed a certification of market readiness, requesting an effective date of February 1, 2007.**

**In the January 26 order FERC declines to further delay the start of the imbalance market and notes that SPP had complied with all requirements outlined in previous orders: “SPP indicates that it has made operational the necessary systems for market start-up, conducted numerous tests and certified that testing and other issues will be addressed prior to market start. NERC review indicates, from a reliability perspective, that SPP is ready for market implementation. Further, SPP’s final decision to actually implement the imbalance market will be made in consultation with the Go/No-Go Advisory Team who consists of the chairs of various SPP stakeholder committees, task forces and working groups, as well as SPP staff, SPP’s board of directors, the RSC and the Strategic Planning Committee.”**

**D. PJM Reliability Pricing Settlement  
FERC Docket No. ER05-1410**

---

**On December 22, 2006 FERC conditionally approved a settlement filed by PJM Interconnection, L.L.C. (PJM) and multiple PJM market participants concerning PJM's Reliability Pricing Model (RPM) to establish new market rules that will enable PJM to obtain sufficient energy to reliably meet the needs of consumers within PJM. 117 FERC ¶ 61,263. Unhappy with the conditions FERC imposed, a number of parties withdrew support of the settlement and on January 22, 2007, filed rehearing requests asking FERC to clarify, stay, and in one case, vacate the order.**

*Background*

PJM's current market rules establish a single market for supply, but the structure does not assure that the supply is available to all local areas. On April 20, 2006, FERC found PJM's existing generation capacity obligation rules to be unjust and unreasonable and agreed with PJM that they must be replaced. FERC indicated that certain elements of the PJM's proposed Reliability Pricing Mechanism ("RPM") might form the basis for a just and reasonable capacity market, but that the plan need to be analyzed further before such a determination is made. In particular, FERC noted that the resulting market must encompass areas that best reflect the operational characteristics and transmission constraints of the PJM system, and ordered a paper hearing to determine how best to achieve this. FERC also agreed with PJM that the daily and monthly procurement system should be replaced with a program that is more conducive to system planning. However, the Commission set for hearing the duration of capacity commitments. PJM had hoped to implement RPM by June of 2006.

On September 29, 2006, PJM submitted a settlement agreement to FERC that purportedly resolved all outstanding issues between parties. The key features of the new RPM include:

- Determination of prices through use of a downward-sloping demand curve. This is a mechanism to price supply within each local area so that prices change gradually based on the balance between the amount of supply offered and the amount required for reliability. It encourages investment by increasing revenue stability over time. It also better indicates the incremental value of capacity at different capacity levels than the current mechanism, where prices change abruptly with small changes in supply around the reliability requirement. In addition, this mechanism is anticipated to reduce the incentive for sellers to withhold capacity in order to exercise market power by decreasing the potential to obtain excessive profits through market manipulation. Further, the settlement includes a provision under which qualifying utilities that prefer not to participate in this mechanism may choose instead to fulfill their own reliability responsibilities.
- Forward procurement. Under the settlement, load-serving entities must make commitments to procure a sufficient supply of energy three years ahead, rather than the shorter term commitments that are common now.
- Locational pricing phase-in. The settlement provides that PJM will create 23 Locational Delivery Areas for the determination of prices, but that division of the market will be completed incrementally through delivery year 2010-2011, so as to allow time for market participants to realign their contractual obligations.

On December 22, 2006, FERC conditionally approved the Settlement Agreement but made some changes to its terms. The major provisions of the Settlement are summarized as follows:

- In order to assure that sufficient supply is obtained for local areas, the Settlement provides that each company providing electricity to customers throughout PJM is required to supply or purchase resources to provide sufficient electricity to meet the reliability targets for its service areas. The Settlement therefore creates separate areas (Locational Delivery Areas) within PJM, and requires that generation and transmission to those areas be sufficient to provide reliable service.
- The Settlement provides that utilities can supply their energy needs through a combination of generation, transmission, and demand response, including energy efficiency.
- Prices will be set in each area to reflect the needs of each area. The Settlement provides for prices to be set through an auction market with a demand curve that reflects the reliability value of increased supply. The demand curve is expected to decrease the volatility of the market and thereby create a better market environment for investment in new generation and retention of existing plants as well as in demand response programs. Utilities that prefer not to participate in the auction market and that meet certain other requirements may procure a pre-determined amount of supply outside the auction sufficient to ensure reliability for their customers.

- To increase the opportunities for competition from new entry, the Settlement provides that companies providing service to customers must contract with suppliers three years in advance to ensure that reliability goals are met and that current generators as well as new generators can be assured of sufficient revenues to either retain their current investment in PJM, or invest in constructing new generating units.

The settlement includes a number of design features that discourage the exercise of market power and market manipulation generally. Specific mitigation rules and increased competition from new entry are the most important design elements in this regard. Additionally, since this market design is anticipated to decrease price spikes, it is likely to provide fewer incentives for sellers to exercise market power by withholding supply from the market.

The settlement requires PJM to file changes to the provisions that discriminate between signatories and non-signatories to the settlement, removing the provisions granting discretion to the PJM Market Monitor and revising the tariffs to enable expedited cost recovery.

On January 8, 2007, PJMICC filed a notice of withdrawal from the settlement, citing concern with some of the conditions FERC had imposed. In particular, PJMICC stated that the expansion of the class of generation owners eligible to add Mandatory Capital Expenditures to otherwise applicable offer caps, the expansion of generation owners eligible for the “offer adder safe harbor,” and the requirement that PJM develop and file changes to the MMU’s authority “combine to add risk to customers in the PJM region that was not contemplated by the Settlement and that is not offset by customer-oriented benefits.” Portland Cement and a small number of others also filed notices of withdrawal citing similar concerns with FERC’s imposed conditions.

**On January 22, a number of the withdrawing parties, along with others, requested rehearing of FERC’s order approving the settlement. In addition to rehearing, PJMICC asked FERC for a stay of the order, arguing that a stay is appropriate in light of the fact that the first round of RPM auctions is scheduled to take place in early April 2007, while it**

is likely that resolution of the various rehearing requests will extend beyond that date. In the meantime, there will be “significant cost impact of ...RPM implementation on customers, the inability to ensure appropriate refunds once RPM-related costs begin to be charged to ... LSEs and flow through to retail customers, and the need to ensure that customer dollars are not squandered on ill-conceived market design.” Among the errors PJMICC cites in FERC’s December 22 order are: deploying an approach to resource adequacy that is largely administrative without necessary safeguards required by cost-of-service rates; mistakenly presuming that a competitive market will exist under the approved capacity construct and that sellers’ MBR authority under that construct remains lawful; and intruding into the states’ exclusive jurisdiction over generation adequacy by mandating LSE procurement of a reliability product.

A group calling itself the “Indicated Buyers” (including Portland Cement and AF&PA) argue that by imposing conditions on the settlement agreement, FERC “unnecessarily and arbitrarily disrupt[ed] the careful balance of benefits achieved in that Settlement Agreement, unduly biasing the settlement as agreed upon in favor of certain seller interest.” They ask FERC to approve the settlement as it was filed and without condition or modification.

The Maryland Office of People’s Counsel, which had opposed the settlement agreement, protested FERC’s acceptance of a downward sloping demand curve as part of the capacity market, argued that FERC had adopted provisions that will increase prices as a result of rational economic behavior on behalf of load, and accused FERC of making findings and conclusions without a full trial-type evidentiary hearing despite genuine issues of material fact.

**And the New Jersey Board of Public Utilities took issue with the fact that FERC decision is unlikely to make any contribution to resolving local reliability problems. “The only certainty provided by the Settlement Agreement is that it will increase capacity payments and thus cause substantial increases in electricity rates in states like New Jersey far beyond the expected increases in other parts of PJM.”**

**E. NERC Application for FERC Certification as National ERO  
FERC Docket Nos. RR06-1, RM06-16**

On December 1, 2006, NERC filed its “Reliability Standards Development Plan: 2007 — 2009” (Work Plan) with FERC. NERC stated that the Work Plan was submitted to inform the Commission of NERC’s program to improve the Reliability Standards that currently are the subject of the Commission’s October 20, 2006 NOPR. A portion of the Work Plan also is designed to fulfill the commitment NERC made in its April 2006 ERO certification application to provide the Commission with a plan to address the “fill-in-the-blank” regional reliability standards. The informational filing also contains a status report on the violation risk factors that NERC plans to assign to each requirement in its Reliability Standards to help delineate the relative risks associated with the violation of each requirement of a Reliability Standard. FERC asked for comments on the Work Plan to be submitted in conjunction with comments on the October 20, 2006 NOPR.

**Background**

On October 20, 2006, FERC issued a notice of proposed rulemaking, stating its intention to approve 83 of 107 reliability standards proposed by the North American Electric Reliability Council (NERC), though modification of some of the standards will be necessary and will be

ordered pursuant to a final rule. FERC decided not to rule on the 24 remaining standards at this time.

FERC also addressed three other issues:

(a) Definition of bulk electric transmission system: Whereas the industry and proposed standards define the nation's bulk electric transmission system as network facilities of 100,000 volts or higher, the EPAct 2005 is broader and excludes only "local distribution facilities".

FERC attempts to resolve this by stating that during a transition period, the historical standards will be used while the ERO works on a standard consonant with the EPAct.

(b) Interpretation of "user of the bulk power system": FERC proposes to determine who a user of the system is on a standard specific basis in the context of the objective of the relevant standard.

(c) Discretion in considering violations: For the first six months after the new standards are established as mandatory, FERC, the ERO and REs are directed to use discretion in finding standard violations or assessing penalties.

ELCON and others had requested a rehearing or clarification of FERC's July 20, 2006 Order certifying NERC as the ERO. On October 30, FERC denied rehearing.

On January 3, 2007, FERC received numerous comments on the NOPR and on the December 1 informational filing by NERC. Not surprisingly, NERC was pleased with the Commission's conclusion that the 83 standards are just and reasonable. Placing these standards into effect immediately, NERC stated, will allow it to "affirmatively mitigate any noncompliant performance of bulk power system owners, operators and users going into the summer of 2007," and will "serve to create a solid foundation on which to improve and expand the standards ...

without reopening for further debate the underpinnings of standards that have already been approved by stakeholders and utilized in practice by the industry.”

ELCON submitted comments generally supporting the Commission’s proposal to approve 83 reliability standards and designate 24 other standards as “good utility practice” pending further development. ELCON agrees that the Commission should rely on the NERC standards process for further development rather than try to rewrite any standard but notes that improvements need to be made to address recommendations in the August 2003 Blackout Report. Second, ELCON recommends that the term “bulk-power system” as proposed by the Commission be the reliability-based definition currently used by NERC in its term “bulk electric system”. “Erring on the side of registering every potential ‘User of the Bulk-Power System’ will only distract the compliance staff at both NERC and the regions from concentrating their efforts on identifying and monitoring compliance of entities that are most likely to have a material impact” on system reliability. However, any entity reasonably deemed material to reliability should of course be registered and regional entities should have a role in identifying and registering such entities.

Among other industrial user groups commenting on the NOPR or Work Plan, the Process Gas Consumer Group echoed ELCON’s concern that users who have no material effect on reliability of the power system not be unnecessarily burdened and were also in favor of participation in demand response resources. Multiple Intervenors focused on the need to encourage demand response and eliminate unnecessary barriers to demand response participation in energy, capacity and ancillary service markets. To that end, they asked the FERC clarify the NOPR to provide express permission for technically-qualified loads to participate in all ancillary services markets.

EPSA noted the importance of balancing oversight with standards development. They supported FERC's decision to conditionally approve "imperfect" standards subject to future modification of such standards. They encourage FERC to assure that standards are clear and unambiguous regarding what is required and who is required to comply. EPSA expressed concern regarding FERC's proposed "validation period," suggesting that actual penalties might be imposed for violations by aggravated circumstances.

EI similarly commented that enforcement discretion even during the trial period is "essential to the continued success of the program." They stated that they "stand strongly for the principle that all responsible entities should comply at all times with Reliability Standards." EI also expressed concern that certain standards lacked technical features or specificity necessary to be clear and unambiguous. They question how FERC can find such incomplete standards to be just and reasonable.

APPA and NRECA filed comments suggesting that FERC had not satisfied obligations under the Regulatory Flexibility Act to analyze impacts on small entities, and cautioned that this failure could lead to judicial challenges of the standards. They state that FERC may have substantially underestimated the number of small businesses – including "hundreds, if not thousands, of small industrial facilities, small generators and small qualifying facilities that may also meet the small entity definition" -- that will experience significant economic impact. "Most such entities do not own facilities that have a material impact on the reliability of the bulk power grid in this country, yet the NOPR in its current state appears to contemplate that they would all be subject to NERC's mandatory reliability regime."

**F. Conferences on Competition in Wholesale Power Markets**  
**FERC Docket No. AD07-7**

---

The Commission has announced that it will convene a series of public conferences to evaluate the state of competition in wholesale power markets. The first conference will be held on February 27 at FERC headquarters in Washington D.C. The conferences will explore a range of issues, including federal-state cooperation, the need for new infrastructure, demand response and renewable energy, the availability of long-term contracts and market design issues affecting wholesale markets. The Commission will address the challenges faced by all wholesale markets, including organized markets and bilateral contract markets.

Citing significant debate and concern about the costs and benefits of wholesale power markets, FERC says it plans to evaluate the various challenges faced by the different types of wholesale power market structures across the country, with an aim to strengthening the markets in all regions. These conferences will provide a forum for affected stakeholders – including state regulators, consumers, generation suppliers and transmission providers – to discuss the critical issues and identify potential solutions. ELCON and EPSA have praised FERC for recognizing the need to engage in formal discussion on the effectiveness of the power markets.

**G. FERC terminates ISO-NE PUSH mechanism**  
**FERC Docket No. ER07-219**

---

**On January 12, 2007, FERC issued an order terminating the ISO-NE’s “peaking unit safe harbor” (PUSH) mechanism as of June 19, 2007. 118 FERC ¶61,018. In 2002, the Commission approved a new market design for New England energy markets. The proposed market design created Designated Congestion Areas (DCA) for chronically**

constrained regions, and provided mechanisms to address scarcity pricing in the capacity market and appropriate compensation for reliability units in constrained regions, including use of RMR contracts. In 2003, the Commission rejected certain RMR agreements proposed for constrained areas of New England, explaining that RMR agreements should be a last resort and that the proliferation of these agreements is not in the best interest of the competitive market for electricity.<sup>1</sup>

In place since April 2003, the PUSH mechanism was designed to provide generators having a capacity factor of 10% or less as of 2002 a reasonable opportunity to recover fixed and variable costs through market bids rather than utilizing RMR contracts. The mechanism allowed these high-cost units, which typically are dispatched only in periods of peak demand, to raise their energy bids above a level that might otherwise cause concern about potential exercise of market power. The PUSH mechanism was intended to be a temporary program until the summer of 2004, when the region's LICAP plan was originally expected to be operational. However, because the region's capacity market mechanism was not approved until June of 2006, and despite complaints of windfall payments to generators, the mechanism remained available to generators in capacity-constrained areas. In November 2006, the ISO-NE and New England Power Pool jointly requested that FERC issue an order eliminating the program effective January 19, 2007.

In the January 12 order, FERC emphasized that the PUSH mechanism was never intended to be a long-term program and that it had never functioned as intended.

Numerous PUSH eligible generators have opted to operate under RMR agreements and do

---

<sup>1</sup> See e.g., *Devon Power LLC*, 102 FERC ¶ 61,314 (2003) (*Devon I*) and *Devon Power LLC*, 103 FERC ¶ 61,082 (2003) (*Devon II*), *reh'g granted in part and denied in part*, 104 FERC ¶ 61,123 (2003) (*Devon III*); *PPL Wallingford Energy LLC*, 103 FERC ¶ 61,085, *reh'g granted in part and denied in part*, 105 FERC ¶ 61,324 (2003) (*PPL Wallingford*).

not rely on PUSH bidding. In the meantime, the ISO-NE has implemented market mechanisms which provide better price signals and ensure adequate resources to support reliability. However, FERC expressed concern with terminating the mechanism too suddenly, noting that some generators needed for reliability may need time to enter RMR contracts, particularly in situations where “market participants are not induced by price signals to voluntarily arrange for sufficient capacity to ensure reliability, and [where] a generator needed for reliability is not earning adequate revenues through the market.”

## **II. STATE PROCEEDINGS**

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

In December of 2005, the California Public Utilities Commission (CPUC) instituted a rulemaking proceeding to consider features of a resource adequacy requirements (RAR) program, including capacity markets in California, that had been proposed in an earlier proceeding. The previous proceeding had led to the establishment of the CPUC’s RAR policy:

First, the Commission seeks through RAR to ensure that the infrastructure investment required for reliability actually occurs. Second, the Commission seeks to ensure that the generation capacity made possible through that investment is available to the grid at the times and at the locations it is needed. Third, the Commission intends that capacity must be sufficient for stressed conditions, i.e., sufficient generation should be available under peak demand conditions even when there are unexpected outages. Finally, the Commission noted that the traditional utility role in procurement included the responsibility to provide reliable service at least cost, and that this is one of the “same issues” of traditional resource procurement that RAR seeks to address. Thus, the concept embodied in the phrase “reliability at any cost” is not a policy option. Ultimately, measures that are proposed to promote

greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability.

Order Instituting Rulemaking, December 15, 2005 (R.05-12-013), at 4 (available at [www.cpuc.ca.gov](http://www.cpuc.ca.gov)).

The CPUC announced that its intention in this rulemaking is to give effect its RAR policy, with the first priority being the development and implementation of a local capacity component. Other matters to be considered in the rulemaking proceeding include whether the RAR program is appropriate for smaller and multi-jurisdictional IOUs and clarification of procurement obligations and consequences for noncompliance. The proceeding was divided into two phases. Phase one, which is now well underway, includes discussion of local RAR issues, tradable capacity product, and penalties for noncompliance. Among the topics for consideration in Phase 2 are multi-year RAR; zonal RAR; and the establishment of appropriate RAR for smaller entities; and (of particular interest to ELCON) discussion of capacity markets, including whether and how to develop a centralized capacity market regime. Phase 2 will include review of the August 25, 2005 CPUC Capacity Markets White Paper in which the CPUC Energy Division weighs some general pros and cons of capacity markets, looks at existing capacity market models and makes a number of recommendations regarding design issues for the California market:

1. Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for CAISO
2. Further investigate alternative availability metrics (e.g. UCAP v. ISO-NE's proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products.
3. Consider subtraction of peak energy rents from the capacity payment.
4. Adopt reasonable locational installed capacity requirements with locally

varying demand curves.

**5. Consider protecting against capacity exports during time of tight supply through the use of capacity prices that fluctuate seasonally.**

**6. Investigate the dependability of capacity import contracts during times of high West-wide load.**

**7. Make the fixed-cost recovery curve explicit.**

**8. Strive for regulatory credibility.**

**On February 1, 2007, ELCON filed a motion to intervene in this proceeding.**

**Phase 2 proposals and comments are due March 16, 2007.**

### **III. COURT PROCEEDINGS**

#### **A. Ninth Circuit reverses FERC treatment of long-term power contracts in California**

The Ninth Circuit issued two companion decisions on December 19 of considerable significance reversing FERC's treatment of long-term power contracts entered into by the California Public Utilities Commission and the California Electric Oversight Board at the time of the California energy crisis in 2001. See Pub. Util. Dist. No. 1 of Snohomish County v. FERC, 2006 U.S. App. LEXIS 31297 (9<sup>th</sup> Cir. 2006); Pub. Util. Comm'n of Cal. v. FERC, 2006 U.S. App. LEXIS 31140 (9<sup>th</sup> Cir. 2006).

These decisions emphasize, first, that the fundamental purpose of the rate authority that FERC exercises under the Federal Power Act is to protect consumers. This general language will be useful to ELCON advocacy in a variety of contexts. Secondly, the decision holds that FERC abdicated its statutory responsibility to assure that wholesale contract rates are just and reasonable (J&R) when the Commission decided that market-based rate (MBR) contracts are somehow pre approved because at the time MBR authorization is granted, FERC has determined

that the contracts are in the public interest. FERC could not ignore that at the time the forward contracts at issue were entered into, their own Staff Report had found that the markets were dysfunctional. The court ruled that Mobile-Sierra cannot apply without determination that the challenged contract was initially formed free from the influence of improper factors, such as market manipulation, the leverage of market power, or an otherwise dysfunctional market.

The decisions are of considerable importance as FERC initiates a proceeding, prompted by ELCON and other allies, to revisit whether the wholesale markets are functioning in competitive fashion.

The court emphasized that the FPA requires FERC to benefit consumers, and that benefit to consumers is the ultimate purpose of FERC's review of wholesale prices under Sections 205 and 206. The court then turned to a discussion of the standard of review of the challenged contracts, observing that the parties and some of the cases speak as if two alternative standards for reviewing wholesale electricity contract rates exist -- the statutory "just and reasonable" standard and the Mobile-Sierra "public interest" standard. The court found that there is a single general, standard for FERC's adjudication of contract challenges like the present one: whether the challenged contract is "just and reasonable." The question therefore cannot be not whether the Mobile-Sierra or the "just and reasonable" standard of review applies.

The original Mobile-Sierra cases, which arose in the context of sellers seeking relief from low-rate contracts, hold that lack of profitability alone is not a basis for deeming a contract unreasonable when the seller has agreed to the rate that proves unprofitable. The Ninth Circuit noted that at the time that Mobile-Sierra was adopted, FERC approved individual contracts, which the Commission does not do under the current market-based rate regime where it has pre-approved the seller on the basis that the seller has no market power. The market-based rate

regime differs from the regulatory context present in the Mobile-Sierra cases in two material respects: (1) the *timing* of the agency's initial review has moved to a point *before* contract formation, and (2) the *substance* of that review no longer focuses on the *terms of the contract*. 2006 U.S. App. LEXIS 31297 at\*17.

The court applied a tripartite analysis in considering whether forward contracts entered into during the western markets crisis were just and reasonable.

*First*, the court considered whether the contracts were subject to Mobile-Sierra review. Since the contracts called for or were silent with respect to applicability of the Mobile-Sierra standard, the court agreed with FERC that as a contractual matter the Mobile Sierra standard could be applied.

*Second*, the court focused on whether FERC's process allowed for timely and effective review of rates. The court found that FERC's review did not pass muster. The court found that market-based rate authority *can* qualify as sufficient prior review to justify limited Mobile-Sierra review only "when accompanied by effective oversight permitting timely reconsideration of market-based authorization if market conditions change." Here, the fatal flaw in FERC's approach to 'oversight' is that "it precludes timely consideration of sudden market changes and offers no protection to purchasers victimized by the abuses of sellers or dysfunctional market conditions that FERC itself only notices in hindsight."

The court rejected FERC's contention that the loose oversight scheme of market based rates passed muster:

A hypothetical explains the dilemma with FERC's present "oversight scheme": Seller A receives market-based rate authority in Year 1. In Year 5, prices increase dramatically in short-term markets. Buyer B, needing to escape these markets, agrees to long-term contracts X, Y, and Z to buy wholesale energy from Seller A. Buyer B agrees to the contract terms because in a frantic market Seller A is one of the only suppliers willing to enter into a long-term contract, and Buyer B needs to

ensure that its supply is able to meet the load required by its retail customers. In its next required quarterly report in Year 6, Seller A dutifully transfers the proper information about its rates to FERC. FERC -- perhaps reviewing contracts X, Y, and Z -- discovers that the assumption of a functioning market underlying its approval of market-based rate authority for Seller A does not accord with the rates being charged in forward contracts generally, or in those entered by Seller A in particular. FERC therefore revokes Seller A's market-based rate authority. FERC's action, however, will do nothing to reform those troubling contracts.

Under this regime, FERC has *no* opportunity to review whether contracts X, Y, and Z are just and reasonable before they are entered. As FERC itself recognizes, revocation of market-based rate authority in Year 6 in the above hypothetical can only provide relief for contracts prospectively. FERC applies the Mobile-Sierra presumption that long-term bilateral contracts will reflect just and reasonable rates, without *any* opportunity for initial review of the rates. This, according to the court, amounts to an abdication of FERC's statutory duty to provide rate revision when necessary to assure just and reasonable rates. The court noted that the facts of the western markets crisis match the hypothetical: in 2003, FERC revoked Enron's market-based rate authority prospectively, but subsequently denied Nevada Power's request to reform its contracts with Enron even though the contracts were made during the period of abuse.

The court does not deny that FERC may adopt a market-based rate regime "if sufficient safeguards are taken to provide for sufficient oversight." However, FERC cannot use the choice of the market-based rate regime and couple with it Mobile-Sierra to adopt a process that precludes ordinary rate review, including the propriety of a grant of market-based rate authority at the time the contracts become effective.

*Third*, the Ninth Circuit held that FERC erred by adhering to Mobile-Sierra without considering market conditions at the time the contracts were formed: "Mobile-Sierra cannot apply without determination that the challenged contract was initially formed free from the

influence of improper factors, such as market manipulation, the leverage of market power, or an otherwise dysfunctional market.” While FERC acknowledged its Staff Report that the western markets were dysfunctional, FERC failed to consider whether the influence of the spot markets on the forward markets reached a level sufficient to raise the question whether two parties could negotiate a just and reasonable contract triggering the Mobile-Sierra presumption. FERC failed to consider whether the contracts in question were entered into in fully functioning markets as a prerequisite to whether Mobile-Sierra should apply.

The court found that FERC further compounded the error by applying Mobile-Sierra analysis taken from the context of low-rate challenges to high-rate challenges. In a *low rate* case like the Sierra/Papago context, the important “public interest” concerns relate to the selling utility’s solvency and assuring that under recovered costs are not recouped from other customers. In contrast in a *high-rate* challenge, the public interest requires that the consuming public not be required to pay a rate too high to fall within the zone of reasonableness.

The court ordered remand so that FERC would consider whether excessive rates were paid in each of these proceedings: Snohomish, where the challenged contract accounted for an 8% increase for retail rate payers over 2001 rates; Southern Cal Water’s rate increase of 38%; and Nevada Power, where although retail rates decreased after the contract was entered, this factor did not excuse FERC from considering the public interest as rates may have increased so high because of dysfunction in the spot market that consumers still paid more under the forward contracts than they should have. A similar ruling was issued in the California Public Utility Commission companion case.

ELCON will wish to emphasize these rulings to FERC as it presses the Commission on the need to address dysfunctional markets. While the Ninth Circuit opinion is not dispositive in

other circuits (outside of the West Coast) and other courts may or may not adopt the same reading of the contours of the Mobile-Sierra test, it is not a precedent that FERC can ignore.

**B. Alcoa files petition for review in D.C. Circuit regarding allocation of ERO costs Case no. 06-1426; FERC Docket No. RR06-1-000**

On July 20, 2006, the Commission certified NERC as the Electricity Reliability Organization (ERO) for the United States. Alcoa, Inc. did not seek rehearing of the certification, but in its request filed on August 21, 2006, sought rehearing on the issues of allocation of ERO costs and the rejection of a requirement that proposed reliability standards be subject to a cost-benefit analysis as part of the determination of necessity to achieve reliability.

Alcoa argued that the Commission erred in disallowing its requests to:

- (a) require NERC to allocate costs on a net energy for load (NEL ) basis;
- (b) use the NEL methodology to allocate costs to load served by generation located behind-the-meter ; and
- (c) use a cost-benefit analysis as part of its standards development process.

FERC denied Alcoa's rehearing request on October 30, 2006. 117 FERC ¶ 61,126.

On December 29, 2006, Alcoa filed a petition for review of this matter in the D.C. Circuit.

There has been no significant court activity on this case yet.

Sara D. Schotland  
Jennifer Morrissey