Energy Choice Matters
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FERC Rejects New CONE Data for RPM Auction

PJM's May RPM auction will not use updated Cost of New Entry (CONE) figures because the RTO failed to follow the schedule for changing CONE data approved in its tariff, FERC ruled (ER08-516).

In January, PJM had asked to update CONE for rapidly escalating costs of power plant construction (Matters, 3/24/08), but FERC noted the tariff called for any such changes to be announced by Sept. 1 of the prior year, to give stakeholders an opportunity to vet any changes.

PJM, "failed to establish that its proposal to revise that provision is necessary on a one-time emergency basis to ensure reliable service," FERC explained.

Since CONE prices ultimately dictate the Variable Resource Requirement curve and thus capacity prices paid by end-use customers, PJM's tariff provisions requiring adequate notice and scheduling, "are not merely procedural formalities that can be said to have no significant impact on market participants," the Commission held.

The four-month review period for new CONE data also gives customers the ability to mitigate against potentially high prices and to physically hedge their positions by making prudent business decisions regarding impending RPM price increases, FERC added.

The four-month review period is, "an important, if not critical, element of the bargain struck by the parties to the RPM Settlement," the Commission concluded.

"While PJM vaguely suggests that a 'significant reliability concern' motivates its filing, it provides no support for the claim," FERC explained.

"If PJM believes that CONE needs to be reset for its 2009 auction, it needs to follow the provisions in its existing tariff providing sufficient time for stakeholder review of the analysis and advance planning. In making such a filing, PJM and the stakeholders need to consider whether PJM's proposed method of calculating CONE by using projected values, including inflation,

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FERC OKs Higher Price Floor for ISO-NE Demand Response Program

FERC accepted ISO New England's modifications to its Day-Ahead Load Response Program (DALRP) to adjust the minimum offer price from a fixed $50/MWh to an indexed amount that reflects current fuel prices (ER08-538).

The ISO asked for the change, which would set the price floor to about $121/MWh, because of what it considered gaming of the baselines used to measure demand reductions, and the resulting "phantom" demand response (Matters, 2/8/08).

Industrials objected, arguing the change would deny customers payments for permanently shifting load.

FERC determined an updated minimum offer price is appropriate since the $50 mark was set in 2002 when natural gas prices were less than $4/MMBtu. Now gas costs $7-10/MMBtu and day-ahead LMPs exceed $50/MWh approximately 84% of the time.

Total DALRP payments have grown almost tenfold from in just one year, from $1.74 million in 2006 to $16.81 million in 2007. Over half of those payments - about $8.7 million - are associated with static customer baselines, and the proportion of payments associated with static customer baselines grew 68% from July 2007 through December 2007.

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Maryland RFP-Style Auction May Not Give Best Incentive for Lowest Price

Maryland's RFP-style procurement of SOS may produce higher prices than the much-derided descending clock wholesale auctions that Illinois recently abandoned, Kaye Scholer suggested in its report regarding SOS auctions.

As reported last week, Kaye Scholer found Maryland's auctions to be competitive, with the resulting prices reasonably reflecting prices for comparable products in the wholesale market (Matters, 4/2/08).

In the complete, but redacted, report released Friday, Kaye Scholer noted the merits of the descending clock-style auction used by New Jersey and used by Illinois in its initial move to market-based SOS. For various reasons, the descending clock auctions have fallen out of favor with some policymakers who believe a portfolio management approach using RFPs and bilateral negotiations can produce lower prices.

But Kaye Scholer observed that the descending clock auctions are designed to keep lowering prices and enable transparent price discovery, while a sealed-bid RFP may offer other incentives.

"Unlike descending clock auctions in which the bid prices automatically decrease over the course of the auctions, Maryland's sealed bid process may not give bidders as strong an incentive to bid their lowest possible price," Kaye Scholer explained.

"Instead, Maryland's SOS bidders may try to guess the highest bid that can still win. If bidders can estimate the highest reasonable market price -- *i.e.*, the PAT [Price Anomaly Threshold] -- they have an incentive to bid only low enough to win the supply, while keeping their bids as high as possible. Although the PAT essentially calculates a market-based price cap, neither it nor the RFP bid process ensures actual competition," Kaye Scholer concluded.

Kaye Scholer noted that while the 2004 and 2005 auctions were very robust, the 2006 SOS auctions had fewer competitors, and had prices that triggered the PAT in the first round.

The PAT was ultimately raised, with the approval of the Office of People's Counsel and PSC staff, after changing its composition to reflect costs of Auction Revenue Rights to price congestion (rather than simply comparing the difference between PJM's Western hub and the LMP at each of the utilities); to reflect the most up-to-date data rather than data from earlier in the day or month; and to use weighted averages between summer and non-summer months instead of a simple average.

Kaye Scholer reported the changes appeared to have been appropriate and found no evidence that the PAT was biased or miscalculated to produce higher than market prices.

The substantial increase in prices in the 2006 auctions, "simply reflected changes in market prices driven by higher, more volatile fuel prices and the wholesale market structure itself," Kaye Scholer found. Boston Pacific, the PSC's consultant for the 2006 auction, attributed the less robust level of competition due to uncertainty and market volatility in the wake of hurricanes Katrina and Rita.

Kaye Scholer, "found no evidence to support a conclusion that SOS prices exceeded market prices for comparable service."

Kaye Scholer also criticized conclusions drawn by the Illinois attorney general regarding the results of the Illinois 2006 SOS auction.

In a much-touted FERC complaint, the AG argued the auction prices were unreasonable because they were 40% higher than bilateral prices.

"As the independent, third-party Auction Manager of the Illinois auction showed, however, the AG compared two dissimilar products," Kaye Scholer concluded.

The Illinois products, like the product in Maryland's SOS auctions, were for full requirements service, including energy, capacity, some transmission, load following and other ancillary services. The bilateral prices cited by the AG were for energy-only products that included fixed quantities and a fixed delivery schedule. When accounting for the risks inherent in full requirements, load following service, the Illinois auction prices were actually below market benchmarks, Kaye Scholer confirmed.

Kaye Scholer agreed that there appears to be no "smoking gun" in the Illinois AG complaint that should cast doubt on Maryland's SOS results.

Kaye Scholer concluded that there is "no indication" from the SOS auction results that Constellation or any other supplier had market power that could increase the prices above a competitive level. Constellation won more tranches in the 2006 auction because it was the lowest bidder, Kaye Scholer noted. If Constellation had market power, it would have won contracts on the margin, with the highest winning bids.

RESA, NSTAR Trade Shots in Latest Green Briefs

NSTAR "has not even come close" to meeting its burden to show that it should become the first Massachusetts utility to re-enter the supply business since the state's restructuring law was passed in 1997, RESA said in a brief in the NSTAR green case (07-64).

NSTAR shareholders, "bear absolutely no risk," from the wind power contracts the utility wants to execute, RESA argued, which is why NSTAR has submitted, "incomplete and non-transparent," analyses to support its petition.

With shareholders not facing any risk, NSTAR has no incentive to minimize the power costs paid by green and basic service customers, RESA added.

For example, NSTAR did not evaluate the operating and maintenance schedules of the two wind farms because the utility does not bear the risks, RESA pointed out.

A, "careful approach to ensuring least-cost supply apparently lost out to NSATR's corporate interest in receiving pro-green goodwill and gaining Department authorization to re-enter the portfolio management business for the first time since Restructuring," RESA charged.

RESA reiterated expert testimony showing that the wind contracts would produce an added charge, not a credit, to customers and would actually increase price volatility since basic service customers would bear the price risk of hourly energy settlement (Matters, 2/29/08).

NSTAR, however, responded that the wind contracts are structured so that the electricity that is generated by the facilities will be sold into the market as a price taker and will function to lower the market price for all customers regardless of the ultimate clearing price in any given hour.

The contracts represent a small fraction (60 MW) of NSTAR's total basic service demand of 2,500 MW, the utility added, and customers are protected from risk relating to production of energy from the wind facilities through NSATR's basic service contracts.

The basic service contracts provide approximately 2,500 megawatts of firm, load-following service that includes energy, capacity and the ancillary services that are necessary to ensure the reliability and availability of electric supply 24 hours per day, NSTAR argued.

DPUC Orders a Dozen Retailers to Hearing on CL&P Backbilling

The Connecticut DPUC summoned 12 competitive retailers with customers affected by Connecticut Light & Power's January billing error to an April 15 hearing regarding their billing (08-02-06).

The DPUC is requiring testimony from retailers regarding how CL&P's billing error has impacted their billing practices; how many of their customers were impacted and how were they billed since January 2008; how many of those customers have paid their bills; and how the retailer proposes to resolve any remaining issues (Matters, 4/4/08).

The DPUC also requested a copy of all payment arrangements, if any, that a retailer has entered into with customers arising from the CL&P billing problems.

The Department reminded retailers that Conn. Gen. Stat. §16-259a applies to competitive suppliers, noting the, "section contains strict provisions governing the payment plans that public service companies as well as suppliers may impose on customers resulting from inaccurate billing."

The retailers summoned (and thus having

at least one customer in affected CL&P rate classes: 1, 5, 7, 27, 30, 35, 40, 41, 55, 56, or 58) were Consolidated Edison Solutions, Constellation NewEnergy, Direct Energy, Dominion Retail, Glacial Energy, Hess, Integrys Energy Services, Public Power and Utility, Sempra Energy Solutions, Strategic Energy, Suez Energy Resources NA and TransCanada Power Marketing.

DPUC Draft Says Wait Until 2009 on Another Summer Savers Rebate

A second attempt at a Summer Saver Rewards Program should be delayed until 2009, the Connecticut DPUC would rule under a draft decision (07-06-21).

The program, adopted by lawmakers last year, gave customers bill credits for reducing their summer usage 10%, 15% or 20% versus their 2006 usage.

Although utilities haven't provided adequate information to determine the actual cost effectiveness of the program, the DPUC in its draft, based on the information that has been reported, believes that the program was not cost effective in 2007.

The draft faults the auto-enrollment element of the program as one of the biggest drawbacks of the 2007 program. Due to the late passage of legislation, the program, which originally called for customers to actively enroll to be eligible for rebates, was modified so that all customers residing at the same location during the program were eligible for credits regardless of whether they actually enrolled. These customers were automatically enrolled.

That has made cost effectiveness difficult to determine because it is uncertain whether energy savings were a result of the program.

What is clear is that over $21 million was paid by utilities in credits, compared with a total Conservation & Load Management budget of $100 million in 2008.

The vast majority of credits, nearly $20 million, went to customers who were automatically enrolled in the program. Only $1.3 million went to self-enrolled customers. Of customers receiving a credit, 94% were automatically enrolled, and 94% of saved kWhs were attributed to automatic enrollment customers.

"Many or possibly most of the recipients may have received credits without a conscious decision or effort to participate," the draft decision observed.

CL&P reported that auto enrollment allowed many customers to receive a credit for unrelated reasons, such as the timing of vacations or other, non-conservation related actions.

"Those that did conserve may have taken action before the program was announced in response to significant increase to electric rates that occurred in January of 2007. For these reasons many of the customers receiving credits may be 'free riders,' customers that receive a credit or incentive for actions that were not a result of the program," the DPUC draft states.

"Paying large numbers of free riders can significantly reduce the cost effectiveness of conservation programs, and has likely done so with Summer Saver Program," the draft would conclude.

Noting that the $24 million total cost of the program (including marketing and administration) is a "huge investment," the draft suggests narrowing the focus of the program, including limiting it to residential customers, if the program is adopted again.

The draft favors a delay in renewing the program until 2009 so a more through cost-benefit study can be completed, and so that costs may be reduced through refinement and better preparation.

Finally, any renewal of the program should require self-enrollment for customers to receive credits, the draft would conclude.

Generators Argue RPM Technical Conference Would Be Premature

Generators urged FERC not to convene a requested technical conference solely on PJM's RPM capacity market because two reviews are already underway and additional uncertainty would harm the market (ER05-1410).

State regulators and load representatives under the banner of RPM Buyers want FERC to hold a technical conference on the capacity market structure because it hasn't met their expectations (Matters, 4/3/08).

But the PJM Power Providers Group (P3) urged the Commission to keep in mind that the very first RPM auction was held less than a year ago.

Although four base residual auctions have been held to date with promising results, they have occurred in a compressed time frame and, alone, cannot support a valid prediction about RPM's long-term results, P3 argued.

Still, the four base auctions have resulted in a net minimum increase in capacity of 10,000 MW compared to what would have been available absent the auctions, P3 explained.

"RPM Buyers also ignore the fact that revenues to generators have not been sufficient to support new entry of capacity, for years, almost since PJM's inception," P3 added.

RPM Buyers' motion is based on patently unrealistic expectations that substantial investments could have been committed in the brief time RPM has been in effect, P3 countered.

EPSA found that the conference request, "is part of an on-going pattern by RPM Buyers (individually or collectively) to brandish RPM as a failure and call for investigation (and eventual evisceration) of the mechanism and results to date before it has been fully implemented."

"These actions are harmful to and distract from the serious efforts by PJM and other PJM market participants to develop a responsive, well-functioning marketplace that includes the necessary investment and innovation to ensure reliability and competitive outcomes for the ultimate benefit of consumers," EPSA added.

While both generator groups welcome reasoned reviews of RPM, P3 cautioned that, "the Commission should make clear that any review of RPM is to focus on incremental improvements to RPM, not on the adoption of another capacity market model altogether or broad-reaching measures that would substantially modify RPM as it exists today."

Briefly:

Liberty Eyeing Smaller Illinois Customers

Liberty Power Holdings has applied to serve Illinois customers with annual consumptions less than 15,000 kWh (08-0253). It also intends to provide single billing services. It currently has an ARES license to serve larger C&Is.

Retailers Get More Time for Conn. Labels

Competitive retailers have until May 30 to submit their mass market product disclosure labels to the DPUC because of a delay in the DPUC in obtaining and posting environmental data. The DPUC has now posted the data with examples of how retailers should structure their charts in docket 07-05-33. Labels had originally been due April 12.

EnerNOC Gets Delaware Broker License

The Delaware PSC granted EnerNOC an electric supplier certificate allowing it to broker sales and purchases of electric supply services (08-6). EnerNOC intends to offer brokerage services to commercial, industrial, and governmental customers.

Md. Lawmakers Push to Pass Relief Pact

Despite a Senate amendment which would void a $2 billion settlement between Constellation Energy and Maryland (Matters, 4/4/08), policymakers remained confident the needed legislation would get through the General Assembly before the end of session. The House on Friday approved a clean version of the settlement legislation and Senate leaders believe that, now that the Senate has sent its message about deregulation, a compromise removing the provision requiring PSC regulation of new generation will either pass the Senate or be removed in conference. Gov. O'Malley has been lobbying hard for the House version of the bill to pass the Senate today.

FERC OKs NERC Approach to Develop Rules for Retailers

FERC accepted NERC's compliance filing regarding the process of addressing the applicability of mandatory reliability standards on competitive retailer marketers (RC07-4), but stressed it was not pre-judging the substance of NERC's proposal. Rather FERC accepted the two-step procedural plan for addressing any "reliability gap" caused by FERC's earlier decision that classifying competitive retailers in NERC's LSE category was not appropriate. FERC disagreed with protests that NERC had not provided adequate time for stakeholder input in developing a short-term solution, and noted concerns over NERC's proposals were beyond the scope of the immediate filing and should, in the first instance, be raised with NERC.

FERC OKs ConEd Development Sale

FERC approved the sale of Consolidated Edison Development's generation to North American Energy Alliance (EC08-36). North American Energy agreed to hold wholesale customers harmless from costs related to the transaction and not seek changes to reliability must run (RMR) pacts. Although munis protested the deals, arguing the RMR pacts might not even be needed under the new owner's cost structure, FERC reminded that a merger review docket is not the forum for such discussion. Munis can pursue elimination of the RMR pacts in a section 206 proceeding if they desire, the Commission noted (Matters, 2/15/08).

RPM CONE ... From 1

creates a mismatch with the determination of energy and ancillary service revenues, which rely on a historic average of the past three years," the Commission concluded.

ISO-NE DALRP ... From 1

"It is clear that by the sudden growth in DALRP participation and resulting payouts that this problem is expanding rapidly," FERC found.

The outdated offer floor has, "encouraged participants to create the inflated baselines that have enabled the corresponding payments," FERC noted.

Customers who have permanently shifted load to off-peak, "are not available to provide load response in either the DALRP or real time load response program," FERC explained.

That, "poses a threat to system reliability since the system operators will assume that the Customer Baseline reflects a 'normal' non-load response day," the Commission found.

FERC granted the ISO's request to waive the 60-day notification requirement for implementing the change, noting the Commission has waived the rule, "to protect customers from the adverse effects of market dysfunctions."

"ISO-NE has argued convincingly that certain demand responders are taking advantage of a flaw in the tariff as it is currently written to obtain payments for a service that they are not providing," FERC observed.

Since FERC found the ISO's proposal to be just and reasonable, the docket was not the right forum for industrials' petition for the ISO to redesign the energy market to incorporate demand response on an equal footing with generation

Commissioner Jon Wellinghoff dissented in part, and would have directed the ISO to "expeditiously address with its stakeholders the fundamental issues of the existing customer baseline methodology for assessing baselines of demand response participants."

Wellinghoff added that FERC's Office of Enforcement is investigating the ISO's assertions that indicated some customers had been intentionally inflating their baselines.