Energy Choice Matters

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Maryland PSC Orders Bilateral Contracting to Fill Unserved Load

The Maryland PSC directed Baltimore Gas and Electric and Delmarva Power to supply unfilled SOS load through bilateral negotiations, declining to fill open tranches through the spot and futures market at this time (Matters, 1/19/09).

A recent RFP failed to attract acceptable bids for 17 blocks of BGE residential load and two blocks of Delmarva combined residential and Type I commercial load that have been the subject of three RFPs since October 2008. In each RFP, bids exceeded the Price Anomaly Threshold (PAT), which is designed to prevent spikes or other market abnormalities from being reflected in the RFP results.

The utilities had suggested awarding the unfilled tranches to the lowest bidders in the RFP, assuming the bidders would still honor the original price that was rejected due to the PAT. However, the PSC ruled that awarding unfilled load in such a manner would ignore the process put into place in Case 9064, and would specifically ignore the Price Anomaly Threshold.

Instead, pursuant to § 7-510(c)(4)(ii)1.B of the Public Utility Companies Article, Annotated Code of Maryland, the Commission ordered BGE and Delmarva to negotiate bilateral contracts with qualified bidders for their respective service territories whose bids were the lowest bids made for at least one of the unfilled blocks bid in the January 12, 2009 solicitation; provided however, that the price negotiated for any block must be such that it would have been accepted and a contract awarded if such price had been bid during the January 12, 2009 solicitation. It remains to be seen if utilities will be able to negotiate prices lower than those offered during the competitive RFP. Any contracts negotiated are to be filed with the PSC by January 29, with a Commission ruling the next business

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FirstEnergy Fuel Rider Triggers Increase in Shopping Credits, NOPEC Says

PUCO's approval of a fuel rider at the FirstEnergy distribution utilities, which otherwise are charging Rate Certainty Plan (RCP) rates from 2008, triggered provisions in the RCP that require the shopping credit and shopping credit cap provisions to be increased if a fuel-cost based generation rate increase is approved by the Commission, the Northeast Ohio Public Energy Council (NOPEC) and Northwest Ohio Aggregation Coalition (NOAC) argued in a PUCO filing.

The fate of nearly 750,000 customers of NOPEC and NOAC is now at issue, the aggregators said. PUCO approved a new Rider FUEL to recover the purchased power costs of the FirstEnergy utilities for interim supplies procured through March 31, 2009 (Matters, 1/15/09).

"FirstEnergy has unilaterally imposed what may very well be a series of three-month temporary competitive generation solicitations it has designed, without PUCO authorization or meaningful FERC oversight, creating an unregulated de facto temporary MRO [Market Rate Offer]," the aggregators charged.

Without an adjustment to the shopping credit, the 750,000 NOPEC/NOAC customers are captive, "to the whims and caprices of this newly deregulated monopoly obtained by FirstEnergy through gamesmanship with the Commission," the aggregators added.

"The situation FirstEnergy has created is truly insidious: arguing to go to market at wholesale to enrich its FirstEnergy Solutions generation affiliate, while constructing non-justifiable retail barriers to prevent its Large-Scale Governmental Aggregations customers from going to market at retail, thus

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DPU Rejects Nstar-Mirant Tolerance Agreement

The Massachusetts DPU rejected a proposal from Nstar that would have granted Mirant an additional 5% imbalance tolerance for gas deliveries, finding that the agreement would have put ratepayers at risk for increased costs, while compromising reliability (08-GC-1). The arrangement had been opposed by Hess Corporation (Matters, 6/30/08).

The Department determined that the additional flexibility provided to Mirant on Nstar's distribution system could cause daily balances to exceed the tolerance threshold upstream on Algonquin's interstate pipeline, which could result in Algonquin enforcing penalties against Nstar that are ultimately passed onto firm gas sales customers. The additional 5% flexibility for Mirant would cause Nstar to exceed Algonquin's 10% tolerance by one to two percentage points on an average of 10 days during the month of January for each year, and by almost seven percent on a daily basis for the month of July during each year, the DPU said.

The DPU is also concerned that, with no risk of being penalized, Mirant may deliver excess gas back into Nstar's distribution system on warmer days, but that it may not necessarily do so on cold days when Nstar uses LNG to meet gas needs, and when that excess gas could reduce the amount of LNG Nstar would use. If Nstar uses LNG to cure daily imbalances caused by the 5% extra tolerance, as it has indicated it might do, the potential exists that there will not be enough LNG to meet the needs for the remaining winter season, the DPU noted. As a result, Nstar may be forced to either buy more expensive spot gas on cold days, which would increase costs to its firm gas sales service customers or, if such gas is not available, resort to a form of curtailment, which would impact system reliability.

Furthermore, the Mirant proposal would confer a benefit to only one marketer (Mirant's supplier) operating in Nstar’s distribution system, the DPU observed. The proposed additional tolerance would provide Mirant not only with more flexibility, but also with an added financial benefit -- that of avoiding penalties associated with imbalances beyond those allowed in Nstar's existing Terms and Conditions, the Department said. This "direct and new financial benefit" was offered solely to Mirant and not the other competitive suppliers in Nstar's Cambridge Division, and, "could provide Mirant and its supplier with a significant competitive advantage," the DPU held.

Consumers Files for Increased Stranded Cost Charge

Consumers Energy filed to increase the stranded cost recovery surcharge applicable to choice customers, and institute a new bundled customer stranded cost surcharge, because the current fee won't allow Consumers to recover stranded costs within five years of the effective date of Act 286 of 2008, as provided in the Act (U-15744).

Under the current $0.001200/kWh surcharge applicable only to retail access customers, Consumers' stranded costs have actually grown from $63.2 million in 2004 to $70.7 million, because retail access sales have been below assumed levels, resulting in interest being accrued faster than the principal balance can be reduced. Choice sales in 2007, for example, were 88% lower than originally projected, with actual choice sales of approximately 1.4 GWhs compared to originally projected choice sales of approximately 11.2 GWhs.

Thus, Consumers applied to increase the retail access stranded cost recovery surcharge from $0.001200/kWh to $0.001866/kWh. The utility also filed to implement a full service customer stranded cost recovery surcharge of $0.000666/kWh, which maintains the current $0.001200/kWh differential between what is paid by choice customers and bundled customers for stranded cost recovery.

A surcharge on bundled customers is needed because collecting the entire stranded cost balance from choice customers would raise choice rates so much that customers would be driven back to bundled service, necessitating a surcharge on full service customers to recover the costs in any event, Consumers said.

If choice customers were required to pay the entire amount over the next five years, then the current choice stranded cost surcharge would increase from $0.001200/kWh to $0.014867/kWh. "It is not realistic to expect the full amount of the remaining balance to be recovered from [retail access] customers within the relevant five year period," Consumers said.

Recovering the $70.7 million balance entirely from choice customers would increase their stranded cost surcharge 1,139% above the current level. "In addition to resulting in a substantial increase to customers who remained [retail access] customers, such an increase would almost certainly alter the composition of Consumers Energy's sales by precipitating [retail access] customers to migrate back towards bundled service," Consumers noted.

NRG Says DPUC IRP Draft Ignores Statutory Goals

NRG Energy was among a handful of parties who argued that the Connecticut DPUC narrowed the statutory scope of the state's Integrated Resource Plan in a draft decision (Matters, 1/18/09), contrary to the comprehensive supply evaluation contemplated by lawmakers.

In its draft (08-07-01), the DPUC regards the IRP as a reliability backstop, and refused to consider funding of new generation or other resources absent a reliability need. Several parties, including Environment Northeast and NRG Energy, argued that the IRP statute requires the DPUC to evaluate resources for not only on reliability needs, but for obtaining other policy goals, such as cost reductions, environmental benefits, and energy independence.

"The Decision ignores virtually all of the statutory planning factors except for the evaluation of load forecasts and available resources. It assumes, instead, a reactive role with respect to the IRP, positing that the Plan's purpose is to provide a backstop when the markets fail to respond and, as such, should be used sparingly," NRG noted.

NRG, however, claimed the IRP must consider optimization of existing sites and generating units, fuel diversity and supply risks, emission goals and reliability.

"Central to this planning effort is the determination of how best to transition to the future state given the imminent retirements of existing units due to their age, need for environmental retrofits and low capacity revenues available in the Forward Capacity Market ('FCM')," NRG said.

Connecticut Light and Power, which developed an initial IRP reviewed by the Department, reported that it, "found it particularly difficult in this process to obtain information concerning potential retirements from generators." CL&P urged the DPUC to require generators to be more forthcoming with information regarding possible retirements and encouraged legislative action, if necessary, to make this happen. The Department should also consider seeking legislation mandating that generators provide other meaningful data in the IRP process, CL&P said.

NRG also took issue with the draft's finding that there would be adequate Class I renewable resources in the near future, and that no new resources must be built under the IRP. NRG claimed that due to the lack of progress in several renewable projects, along with deterioration of available credit and financing, the future of Class I resources is uncertain.

"Until such time as there is greater certainty that these resources will be built, the Department should favor broad flexibility in contracting opportunities for RECs alone and for bundled REC and energy products," NRG said.

Briefly:

ALJ Approves Intervention of Illinois Competitive Energy Association

An Illinois Commerce Commission ALJ has granted the Illinois Competitive Energy Association's motion for reconsideration and permitted the trade group to intervene in Ameren's POR case (Matters, 1/22/09). The ALJ also gave notice that the Illinois Competitive Energy Association, "shall be prepared to address any apparent inconsistencies among its positions and those of the Retail Energy Supply Association and Constellation NewEnergy, Inc."

PUCT Staff Updates REP Disclosure Proposal

PUCT Staff submitted a revised proposal for adoption regarding new REP disclosure rules, incorporating Commissioners' directives from the last open meeting (35768). The proposal would establish three product types -- fixed, indexed and variable, and would limit residential variable products to month-to-month products only (Matters, 1/15/09). Variable products could still change at the REP's discretion, but REPs would need to provide history of price changes to customers as well as the ability to always obtain the current price, so customers are aware of the price before the next bill. While Commissioners discussed making the variable price history requirement only applicable to residential products, the proposal as written could be construed as requiring such disclosures for all variable products. Subsections of the proposal dealing with the Electricity Facts Label only require the history disclosure for residential customers, but §25.475(c)(2)(G) (general requirements) lists the requirement without any limitation as to customer class. Renewal notices would be required at least 14 days, but no longer than 45 days, before contract expiration, and termination fees could not be applied for 14 days from the date that the notice is sent to the customer.

BGE Files to Apply Credit Related to Type II Mitigation

Baltimore Gas and Electric filed a final reconciliation of the estimated mitigation costs as specified under Rider 29 (Type II Rate Mitigation and Recovery Charge), which results in a credit of $0.00010/kWh for all non-residential customers, effective in the March 2009 billing period. The distribution credit reconciles charges paid by all non-residential customers to mitigate rates during the summer of 2008 for certain customers moving from Type I to Type II rates (Matters, 5/29/08).

Court Denies Blumenthal "Hybrid" Market Complaint

The U.S. Court of Appeals for the D.C. Circuit denied an appeal from Connecticut Attorney General Richard Blumenthal regarding FERC's acceptance of ISO New England Market Rule 1, which permits generators to elect market-based rates or Reliability Must-Run (RMR) agreements. Blumenthal had argued unsuccessfully at FERC that the "hybrid" market allowed low-cost generators to elect high, market-based rates, while allowing high-cost generators to enjoy high, cost-of-service rates under RMR agreements. The Court found that FERC, contrary to the AG's assertion, did not need to find the ISO-NE market to be "workably competitive" before allowing market-based rates. FERC, the Court ruled, only needed to determine that individual sellers could not exercise market power. The AG's proposal to require all generators to be paid at cost-of-service rates is also not just and reasonable, the Court said.

Wellinghoff Named Acting FERC Chief

President Barack Obama named Commissioner Jon Wellinghoff as Acting FERC Chairman on Friday.

Ajello Now With Hawaiian Electric

Hawaiian Electric Industries announced former Reliant Energy senior vice president James Ajello as its new CFO, effective today. Ajello had been senior vice president of business development at Reliant, which has trimmed its large commercial growth strategy to contain collateral costs.

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day. BGE and Delmarva are to use the 2009 Full Requirements Service Agreement as the form of the contract, modified to eliminate any provisions or references stating that the contract was awarded through a bidding or solicitation process.

Although the Commission believes that the use of the spot and futures market may benefit ratepayers if the price for power continues to trend downward or stabilizes at a lower rate than bid during the RFP on January 12, 2009, the PSC rejected such a mechanism at this time, since it would shift certain risks to ratepayers (from the suppliers) in the event that prices increase and the utilities are not hedged to avoid the price increase.

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creating the perfect 'deregulated monopoly,'" NOPEC and NOAC alleged.

Both the shopping credit and cap provisions of the continuing Standard Service Offer under the RCP are designed so that adjustments to the generation charge recovered by FirstEnergy will result in equal adjustments to both the shopping credit and credit cap provisions, the aggregators argued. The recently approved Rider FUEL is an avoidable expense generation charge adjustment currently being incurred by customers that must be reflected in revised shopping credits and caps, NOPEC and NOAC said.

The aggregators urged PUCO to set the shopping credit at the full and avoidable cost of FirstEnergy generation rates which are passed through to Standard Service Offer customers - currently 6.98¢/kWh - which may change as a result of a future competitive bidding process for interim supplies.

The current notice provisions regarding load aggregation should be reduced to 30 days, NOPEC and NOAC added, given that extension of the RCP was not contemplated, and because extended notice is no longer needed to protect the FirstEnergy utilities. In their interim supply procurement, the utilities have shifted shopping and other risks associated with serving as the provider of last resort to the winning suppliers, NOPEC and NOAC noted. Yet the RCP continues to compensate the utilities for assuming the migration risk -- a risk they no longer bear, the aggregators said.

Worried that FirstEnergy could continue to conduct procurements for interim supplies without ever receiving PUCO approval for an MRO, the aggregators recommended that PUCO require FirstEnergy to submit either a new electric security plan or MRO for Commission approval by February 1. PUCO holds such authority, NOPEC and NOAC contended, because under statute utilities "shall" offer customers a Standard Service Offer pursuant to either an ESP or MRO, and PUCO thus has the authority and duty to direct utilities to comply with such a requirement.