Energy Choice Matters

June 22, 2009

NEM Says Maryland Electric POR Should Start in Fall

The implementation of Purchase of Receivables at Maryland's electric utilities should, "commence no later than the fall of 2009," the National Energy Marketers Association said in comments on utility compliance filings (RM 17).

"The unique and favorable market circumstances that currently exist in Maryland justify the resources to quickly put POR in place, so as to allow marketers to serve Maryland customers with competitive options as soon as possible," NEM said. Several Maryland policymakers have highlighted this fall as a deadline to see significant residential migration, given favorable competitive supply pricing under current SOS prices (Matters, 6/19/09).

As only reported in Matters, Delmarva Power and Allegheny Power have filed to implement POR in December 2009 (Matters, 5/22/09). However, Baltimore Gas & Electric and Pepco said it that will take until April 2010 before POR can be implemented.

"The utilities have been on notice for a very long time that POR programs were a component of RM17 and COMAR 20.53. Under these circumstances, delaying implementation until next spring is not reasonable," NEM argued. Utilities have said that expenditures prior to final adoption of RM 17 would have been imprudent, especially if the proposed requirements were altered upon final adoption.

NEM noted that the delay in POR program implementation will be ameliorated somewhat by the willingness of Pepco, Delmarva and Allegheny to purchase receivables that the supplier incurs upon its election to use the utility's consolidated billing system.

However, BGE states that it will not purchase receivables incurred prior to the POR program implementation date in April 2010. "This will likely cause a significant delay in participation by some suppliers," NEM said.

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N.Y. PSC Won't Require ESCOs to Submit Revenue Data as Part of 18-a Assessment

"Estimating ESCO commodity revenues based on each utility's average commodity price provides the most practical, expedient, and reasonable methodology to determine the Temporary State Assessment," the New York PSC said in a written order adopting Staff's recommendation regarding how utilities shall account for ESCO revenues in collecting the expanded Section 18-a assessment (Matters, 6/19/09).

Accordingly, the Commission will require electric and gas utilities to estimate ESCO revenues by multiplying the known amount of electricity or gas delivered to ESCO customers by the commodity supply price charged by the utility for sales to its bundled service customers. ESCOs will not have to supply any sales, revenue or price data as part of the process, as the Commission rejected suggestions which would have imposed such reporting obligations on ESCOs.

The PSC noted that Staff's estimation methodology relies on information that is in the possession of utilities, and allows for swift and timely implementation of the 18-a surcharge, required by the impending September 10, 2009 deadline for payment of the 2009-2010 Temporary State

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Pepco, Delmarva File Type II Rates for Period Beginning Sept. 1

Pepco and Delmarva have filed updated Type II SOS rates for the period Sept 1, 2009 through Nov. 30, 2009:

Pepco (Type II)
Schedule "MGT LV II" (Generation Service Charge)

On-Peak	$0.08378/kWh
Intermediate	$0.08272/kWh
Off-Peak	$0.08192/kWh

Schedule "MGT 3A II" (Generation Service Charge)

On-Peak	$0.08261/kWh
Intermediate	$0.08157/kWh
Off-Peak	$0.08078/kWh

Delmarva (Type II)
Small General Service - Secondary Service "SGS-S"

Energy Rate	$0.079875/kWh

Large General Service - Secondary "LGS-S"

On-Peak Energy Rate	$0.085505/kWh
Off-Peak Energy Rate	$0.073455/kWh

General Service - Primary "GS-P"

On-Peak Energy Rate	$0.082645/kWh
Off-Peak Energy Rate	$0.068825/kWh

Generators Claim FERC Ignored Captive Customers at Nstar, NU in Transmission-PPA Order

Several New England generators have sought rehearing of FERC's May order approving the structure of an agreement among Nstar, Northeast Utilities, and H.Q. Energy Services that will allow Nstar and NU to jointly develop a transmission line into Quebec, to be used to transmit power sourced from HQUS into New England (EL09-20, Matters, 5/22/09).

NextEra Energy Resources, Mirant and TransCanada Power Marketing argued that FERC ignored that Nstar and NU have captive customers which will be harmed by the bundled energy and transmission transaction, and said that new evidence bolsters their contention that the line will be used to import power than is not competitively priced, while having the effect of artificially depressing capacity prices.

In its order, FERC concluded that the line was a participant funded transmission project which had no captive customers, since Nstar and NU customers have retail choice.

"However, if that is the case, the unanswered question is: who pays for the line if these non-captive customers leave NU and NSTAR over the 20 [year] term of the PPA with HQ ... [since] NU and NSTAR are perfectly clear that they intend to assume no shareholder risk in their investment in the line," the indicated generators said.

"[I]f the customers are not there to pay, and the shareholders will take no risk, then who will pay? The only answer left is that NU and NSTAR's captive customers will pay for the line as an unavoidable/non-bypassable wires charge," the generators contended.

"The NU/NSTAR proposal thus is a thinly-masked attempt to evade the fundamental Commission unbundling/anti-monopoly policies established in Order No. 888," the generators added.

The indicated generators also said FERC conducted no analysis to determine whether Nstar's and NU's standard offer service customers are effectively captive despite the existence, in law, of choice.

"Indicated New England Generators demonstrated in their Protest that approximately 4,400 MW of Petitioners' load is comprised of standard offer service customers (i.e., customers that are equivalent to captive customers due to their failure to elect alternate service). The Project's capacity of 1,200 MW of capacity will serve only about 1/3 of Petitioners' captive customers," generators said.

"By acquiring the power from HQUS under the HQ PPA, NU and NSTAR will have both the incentive and the ability to shift the costs of the proposed transmission line to their captive customers regardless of the economic merits. Further, not only will NU and NSTAR have the incentive to erect a barrier to prevent third-party suppliers from competing for load on their systems, through the exclusivity arrangement with HQUS, NU and NSTAR already have taken steps based upon that incentive to block alternative suppliers from serving 1,200 MW of load on their systems for at least a twenty-year period," the generators added.

In their original protests, the generators had estimated the cost of new hydropower units to be built by Hydro Quebec which may provide power for the line at $4,000/kW.

"There now is additional evidence that the power HQUS will sell, and NU and NSTAR propose to buy under the tied arrangements, likely will be priced substantially above alternatives," the generators reported.

Indicated generators cited an article in the Canadian press which reported that the price from the new hydropower units is expected to be 9¢/kWh, from the source to the U.S. border, with HQ CEO Thierry Vandal confirming that the $90/MWh rate only "includes the cost of bringing it to southern Quebec for use or for export."

Even ignoring additional transmission costs, the rate for power under the HQUS PPA will be much higher than today's average price of $54.17/MWh and a projected forward price for 2010 of $64/MWh, generators argued.

"As a result, the transaction structure that the Commission approved in the May 22 Order not only violates the bedrock principles of Order No. 888, but it does so at the risk of burdening Petitioners' captive ratepayers with costs that are far in excess of those that might otherwise be available from alternate suppliers," generators said.

Generators also claimed that the Nstar-NU project undermines the Forward Capacity Market and will defeat specific goals by artificially suppressing prices, thereby sending inaccurate price signals and potentially failing to provide generators the compensation needed to maintain operations.

NASUCA Seeks More Consumer Representation at RTOs

The National Association of State Utility Consumer Advocates released a report last week calling for greater consumer representation in RTO governance.

Specific recommendations include:

- Require at least two seats (approximately 20 percent) on each RTO's board of directors to be for members who have expertise and experience in representing retail customers, at least one of which has expertise with residential customers;
- Develop a standing committee of each RTO's board of directors for consumer issues;
- Implement a department charged with investigating consumer interests into the corporate structure of each RTO, responsible for addressing and furthering consumer interests; and
- Establish funding for use by public consumer advocates to participate in the RTO FERC proceedings, and that will allow them to engage consultants.

NASUCA said residential consumers contribute more than 40% of the country's electricity revenues, and accordingly, a similar contribution towards the operation and management of the different RTOs.

"However, end-use consumers are not consistently able to provide effective input about their interests because the decision-making process is complicated and extremely time-intensive, and most consumers and their advocates lack the resources required to meaningfully monitor and influence the stakeholder process," NASUCA reported.

All stakeholders in the RTO are bound to benefit from a more effective representation of the residential consumer class, NASUCA said, because such representation would assist in adopting more transparent and effective cost control measures, enhancing the linkages between the wholesale and retail markets, increasing the participation of demand side resources, and encouraging a non-adversarial role in generation and transmission siting.

Indiana Commission Opposes Delay in Ruling on PJM Demand Response Filing

The Indiana Utility Regulatory Commission protested PJM's request at FERC for the Commission to delay an order on PJM's application to incorporate tariff changes relating to the ability of retail regulatory authorities to prohibit the registration of end-user demand response resources with PJM's load response programs (ER09-701, Matters, 6/3/09).

Originally, PJM requested FERC approval for its tariff changes prompted by Order 719, which would allow relevant retail regulatory authorities to bar retail customers from participating in PJM demand response programs. However, under PJM's application, retail authorities would only be allowed to either bar all customers from participating, or be required to allow all customers to participate; case-by-case approval or rejections would not be permitted. Several municipal utilities protested that requirement, arguing that Order 719 allows retail authorities to prohibit some customers from participating, while allowing other customers to participate.

In response to the controversy, PJM asked FERC to defer action on its filing until rehearing requests are adjudicated in Order 719, which may impact how FERC rules on PJM's compliance filing. In the interim, PJM said it would abide by its current tariff, which it says does not allow states or utilities to block the registration of retail customers in PJM demand response programs.

That prompted the IURC's protest of the requested delay. Specifically, IURC noted that American Electric Power has stated that PJM has been actively registering Indiana retail customers into PJM's demand response programs without IURC approval, in direct violation of an order issued by the IURC.

"The IURC will investigate this allegation and take appropriate action necessary to address this issue," IURC told FERC.

"Rather than continued delay, it is important that a determination be made and an order issued that clarifies whether FERC Order No. 719 is to act as an abrogation of state jurisdictional authority over retail customers. The IURC continues to assert that, pursuant to Indiana law and the Federal Power Act, it has the authority to regulate the relationship between Indiana utilities and their customers. PJM, as a federally regulated entity, does not have the authority to interfere with the appropriate regulatory function legally exercised by the IURC," the Indiana Commission added.

NYISO Asks for Waivers Related to Error with De Minimis Impact

The New York ISO asked FERC for a waiver to excuse the NYISO from recalculating market clearing prices, revising generator settlements after-the-fact, and revising mitigation results, due to a tariff implementation error that had a "de minimis (but perceptible) impact" on mitigation measures.

NYISO reported that a software change that the NYISO deployed on January 13, 2009, to improve the usability of its Market Information System, had an unanticipated impact on the NYISO's calculation of bid-based start up reference levels for generators from February 4, 2009 to April 2, 2009, and on the NYISO's conduct testing of a small number of generator start-up bids from January 13, 2009 to April 2, 2009.

The change was meant to automatically apply modified start-up bid data to all pending bids that had not yet been "locked" (at market close) for evaluation in the NYISO's Day-Ahead or Real-Time Markets. However, the start-up bid modifications were not carried over to other systems, meaning that for generators that submitted, and then changed, their start-up bid data prior to market close, the NYISO used different start-up bids to commit and settle these generators from the start-up bids that were used to conduct test these generators' bids for mitigation purposes, and to develop bid-based start-up reference levels.

The NYISO identified the following de minimis Real-Time Market impacts that resulted from the error: (i) three instances in which generators' guarantee payments were over-mitigated by a total of approximately $265.04, (ii) two instances in which generators' guarantee payments were under-mitigated by a total of approximately $178.95, and (iii) a negligible (0.7%) impact on the development of the only real-time bid-based start-up reference level that was used in the NYISO markets during the affected period. The Day-Ahead Market was not affected.

Although real-time LMPs could theoretically have been affected by the discontinuity between the bids used for commitment and settlement, and the bids used to apply mitigation, NYISO said that it is not capable of re-running its Real-Time Market to conclusively determine (or disprove) that possibility. However, the NYISO has affirmatively identified only five instances in which mitigation was incorrectly applied, and the NYISO has concluded that any LMP impact would likely be de minimis.

In light of the de minimis financial impacts arising from the error, the NYISO requested waivers from revising the mitigation it applied, recalculating reference levels, revising generator settlements after-the-fact, and revising market clearing prices from January 13, 2009 to April 2, 2009.

Briefly:

Direct to Pay $200,000 for Late Bills Under Settlement with PUCT Staff

Direct Energy would pay $200,000 under a settlement with PUCT Staff to resolve an investigation into the failure of Direct to timely remit monthly bills to customers in April 2009, caused by a complication with the move to a new billing system. PUC Subst. R. §25.479(b)(1) requires a REP to issue a bill monthly to each customer, unless service is provided for a period of less than one month, or the customer agrees to less frequent billing. During Direct's transition to a new billing system a "small percentage" of customers were not issued a monthly bill, and Direct self-reported the problem to Staff. The settlement is subject to Commission approval.

UGI Energy Services Receives D.C. License

The District of Columbia PSC approved UGI Energy Services' application for an electric supplier license. UGI Energy Services intends to market to commercial and industrial customers (Matters, 5/29/09).

D.C. PSC Grants RBS License

The District of Columbia PSC has granted an electric supplier license to The Royal Bank of Scotland. RBS intends to market to commercial, industrial and governmental customers. Affiliate Sempra Energy Solutions already holds a D.C. license.

Glacial Seeking Pa. License

Glacial Energy is currently seeking an electric supplier license in Pennsylvania, to serve all sizes of non-residential customers in all service territories.

MISO Monitor to Raise Conduct, Impact Thresholds Under ASM

The Midwest ISO Independent Market Monitor intends to increase the conduct and impact thresholds for economic withholding under the Ancillary Services Markets tariff from $20 per MW to $30 per MW, as scheduled, effective July 1, 2009, as ongoing monitoring has raised no competitive concerns in the market. In a FERC filing, the IMM noted that the number of offers that are submitted at levels which exceed the generating resources' reference levels by more than $10 are relatively low (generally less than 5 percent of all offers). Furthermore, the frequency of such offers did not increase substantially when the conduct and impact threshold was increased in early April from $10 to $20. Additionally, no mitigation took place during the most recent quarter.

ISO-NE Expects More Technologies in Regulation Pilot

ISO New England's pilot program to open the regulation market to non-generation resources may soon have new technologies participating in addition to Beacon Power's flywheel technology which has been the only participant to date, the ISO reported in an update at FERC (ER08-54-006). One unidentified party is actively completing the steps necessary to interconnect, become a NEPOOL Participant, order and install required communication facilities, and begin hardware, software and communications testing, the ISO said. This potential second participant plans to implement a vehicle-to-grid" or "v2g" technology that will utilize plug-in electric vehicles to provide regulation services. In addition to the flywheel technology that is already being evaluated in the program, and the v2g technology that is anticipated to begin operation later in the year, parties have expressed interest in participating using technologies that include battery storage, demand response resources, and a hybrid renewable energy/storage technology.

PUCT Approves Tenaska LaaRs Settlement

The PUCT approved a settlement between Staff and Tenaska Power Services under which Tenaska will pay $325,000 for failure to deploy 95% of its scheduled third-party Load acting as a Resource (LaaRs) within 10 minutes of ERCOT instruction on July 2, 2007 (Matters, 5/15/09).

Calif. PUC Releases Draft Order on Distributed Generation Cost-Benefit Metrics

The California PUC issued a draft decision posted in R. 08-03-008 to adopt a cost-benefit methodology for distributed generation. Under the proposal, distributed generation should be analyzed using three tests described in the Standard Practice Manual, namely, the Participant Test, the Total Resource Cost Test (including its variant, the Societal Test), and the Program Administrator Cost Test. Additionally, the distributed generation cost-benefit tests should use the avoided cost methodology developed by Energy and Environmental Economics Inc. (E3) and adopted in Decision (D.) 05-04-024, and later updated in D. 06-06-063.

Maryland ... *from 1*

In the event that BGE's POR implementation deadline cannot be shortened, NEM recommended that BGE purchase supplier receivables that were outstanding prior to the start of its POR program and/or follow Pepco's program and agree to purchase receivables incurred upon the supplier's use of utility consolidated billing. NEM noted the practice of purchasing outstanding receivables has been used in other jurisdictions where POR was implemented "mid-stream" in the choice program, such as at Niagara Mohawk and Connecticut Light and Power. Purchasing outstanding receivables will allow suppliers to enter the market and serve BGE customers sooner, NEM said.

All of the utilities propose to limit purchased receivables to commodity or full requirements supply charges, excluding various additional services sold by competitive suppliers (energy efficiency, HVAC, etc.). NEM said such a limitation should not preclude the continued billing for such additional services on utility consolidated bills.

NEM recognized that utilities may incur additional costs in distinguishing between purchased receivables (which may be used for purposes of disconnection) and additional supplier charges (whose nonpayment cannot result in disconnection), and suggested that utilities recover such costs in reasonable fees from suppliers that bill for non-commodity charges.

NEM also stressed that customer dispute resolution in a POR program should be handled in accordance with existing PSC Office of External Relations procedures. Under the utility filings, a customer would initiate the process with the utility, and the utility would withhold payment until it received notice from the customer that the dispute was resolved. "NEM believes that this proposed process is problematic, and is susceptible to [customer] abuse," NEM said, arguing that the proposal inappropriately interjects the utility into the process as a contract administrator for the marketer.

Interstate Gas Supply told the Commission that, "any plans we may have to enter the natural gas choice market in Maryland completely hinges on the implementation of POR ... The single, most important criteria [for entry] is the offering of a POR program." IGS said it will file for a gas supplier license in Maryland upon final adoption and implementation of POR under RM 35, which would require utilities to either offer POR, or pro-rate partial payments equally between supply and delivery charges.

18-a ... *from 1*

Assessment.

"It is not feasible to undertake the more complex, uncertain, and multi-faceted plan to estimate ESCO revenues," proposed by the Public Utility Law Project and Multiple Intervenors, the Commission said, noting that the pricing of ESCO end-user prices is more complex than PULP and MI represent. Furthermore, the contradictory broad conclusions reached by PULP and MI (PULP had claimed Staff's estimation method would underestimate ESCO sales, while MI said Staff's method would overestimate ESCO revenues), "do not provide sufficient justification and analysis for adopting their proposals," the PSC said.

The Commission agreed that the operation of some consolidated billing systems may make the use of ESCO end-user prices unfeasible, and said that additional expenditure to reconfigure the systems to obtain the information would impose additional costs for a temporary charge and add to the increased expenses imposed by the Temporary State Assessment.

The PSC held that, as Consolidated Edison recommended, the commodity price should include both commodity and capacity (pipeline transportation) costs. Regarding balancing costs, for ConEd and Orange & Rockland, such costs shall be excluded from the commodity price because such costs are already included in the delivery rate; and thus, inclusion in the commodity price would result in a double recovery, the Commission said.

As previously noted, the Temporary State Assessment (PSL §18-a(6)) imposes a charge of 2% of gross operating revenues from intrastate utility operations (intrastate gross operating revenues) of electric, gas, steam, and water utilities and jurisdictional municipal corporations, less the amounts assessed for Department of Public Service costs and expenses that are authorized in the annual State Budget.