Energy Choice Matters

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Maryland Industrials Call New Type II Rate Mitigation Unconstitutional

The Maryland PSC does not have the authority to impose rate caps on new Type II customers or impose a distribution charge to fund the mitigation, the Maryland Energy Group argued in supplemental comments on the Commission's mitigation order, which will be heard at today's open meeting (Matters, 5/27/08).

The PSC's decision will increase Baltimore Gas & Electric distribution rates for non-residential customers by $7.4 million, MEG reported.

The Commission's authority is limited only to powers granted by statute, MEG explained, and Maryland law provides only a single provision for capping electric rates - SB 1 from 2006, which authorized the Commission to implement residential deferral programs. The Commission can only implement further residential mitigation where an SOS rate increase exceeds 20%, and only after conducting evidentiary hearings, per Public Utility Companies Article (PUC) §7-510(c)7, MEG insisted.

The Commission has no express authority to extend those provisions to non-residential customers, industrials noted.

MEG questioned the PSC's application of PUC §4-204, which permits suspension of distribution rates pending investigation, to commodity rates.

If the Commission had the power to suspend SOS rates under §4-204, why did the legislature see the need to give the PSC express authority to allow for rate deferral plans for residential customers,

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Amigo Picks Up Variable-Priced National Power Contracts, Remaining Customers Dropped to POLRs

In an unsurprising announcement, National Power Company of Houston informed ERCOT it would not be able to meet financial obligations under the Standard Form Market Participant Agreement, prompting ERCOT to switch customers to POLRs or another REP.

National Power customers on variable contracts will be moved to Amigo Energy, which will honor the contracts' terms. Amigo is not a POLR. Customers on fixed-price contracts will be dropped to POLRs. National Power had a total of 15,163 customers.

The specter of a mass transition for National Power's customers was raised when the REP attempted to raise prices on fixed-price contracts, suggesting an imminent cash crunch (Matters, 5/16/08). Due to public and regulatory outcry, the REP backed away from the price changes.

Market volatility and high energy prices had already claimed Pre-Buy Electric, which had its customers moved to POLRs earlier this month.

National Power's book included 14,721 residential and 442 small non-residential customers, with an associated load of about 616 MWh daily. Its residential customers by service area were:

CenterPoint	9,128
Oncor	4,060
AEP Central	794
Texas New Mexico Power	470
AEP North	252
Sharyland Utilities	17

The PUCT urged customers being dropped to POLRs to quickly find another product in the market to avoid paying high POLR rates.

Industrials See Duke-Ohio Pursuing Different Agendas at Different Regulators

Duke Energy Ohio's application at FERC to transfer its generation into 22 new LLCs, "stands as an example of the regulatory arbitrage that utilities are undertaking to test which venue promises the maximum opportunity to unleash the value of generation assets," Industrial Energy Users-Ohio charged in a protest (EC08-78).

The Duke-Ohio application shows why close FERC-state coordination is needed, the industrials noted (Matters, 5/15/08).

Industrials pointed out that at the state level, Duke had advocated that state guarantees for cost recovery are necessary before the company will invest in new generation, citing testimony from CEO James Rogers during last year's legislative session.

Rogers, industrials reported, urged the legislature to back the 10-year plan that Duke-Ohio proposed in which its Ohio native load customers would guarantee cost recovery for 100% of the cost of new generation facilities.

In Indiana, Duke Energy Indiana proposed the construction of the Edwardsport Integrated Gasification Combined Cycle facility, IEU-Ohio noted, but conditioned pursuing the facility on pre-approval of almost $2 billion in construction costs, with cost recovery from customers during construction before the plant is capable of providing electricity. Duke-Indiana received that pre-approval.

"At the same time Duke seeks guaranteed cost recovery mechanisms at the state level for its generating assets, Duke is urging FERC to enact pricing policies and rules that will raise electricity prices to further enhance the value of its assets," industrials argued.

Industrials pointed to Duke's support for RPM and changes to RPM which would further increase PJM capacity prices (such as updated cost of new entry data).

Despite claims to the contrary, the structure and timing of the Duke-Ohio application, "must be regarded as an attempt to bypass existing PUCO orders and the legislation recently passed by the Ohio General Assembly," IEU-Ohio insisted.

Although Duke assured PUCO and FERC it would not transfer the power plants without PUCO approval, the promises did not satisfy IEU-Ohio.

Duke-Ohio's amended application stops short of conceding any PUCO approvals are necessary, the industrials argued, citing a "carefully worded" letter to PUCO Chair Alan Schriber.

In fact, Duke and its subsidiaries, "deemed it necessary to point out in a footnote that, in making this commitment, they were not waiving any legal rights," IEU-Ohio observed.

Duke has offered "sharply different" legal positions regarding whether its Ohio retail rates are regulated or competitive (and thus would be unaffected by the proposed transaction), IEU-Ohio pointed out.

While Duke-Ohio noted in its application at FERC that it is "well settled" that the generation component of electric service is not subject to PUCO regulation, Duke took a different position in federal court (*Anthony Williams et al. v. Duke Energy International, Inc.*, Case No. 1:08-CV-00046), industrials claimed. In the court case, Duke argued that public utilities such as Duke-Ohio "*must*" charge competitive generation rates approved by PUCO. A utility, Duke added, may not amend its competitive generation rates without PUCO's approval.

The industrials find the statements difficult to reconcile, claiming they, "appear to avoid regulation or seek the protection of it, depending on what is more convenient under the circumstances."

Calif. PUC Draft Would Omit Load Forecasting from Phase I of Local RA Proceeding

A draft decision on local procurement obligations and refinements to California's resource adequacy (RA) program would end phase I of the proceeding without addressing a proposal from Pacific Gas & Electric to change how competitive suppliers forecast their load (Matters, 5/27/08).

The draft (R. 08-01-025) contains no discussion of the under-forecasting issues raised by PG&E and subsequent rebuttal by electric service providers, who, aside from substantive arguments, noted the issue was outside the scope of phase I of the proceeding.

The draft would adopt 2009 local procurement obligations for jurisdictional LSEs, and includes a few refinements to the RA program.

The draft decision would accept the California ISO's proposal that rules for determining a resource's eligibility should focus only on the term "commercial operation," clarifying and simplifying current language. An ALJ determined that a proposal from the Independent Energy Producers Association to evaluate when a unit achieves a percentage of its output could be administratively burdensome.

The ALJ also favors the Energy Division's proposed electronic filing procedures for compliance, and would end the current Advice Letter process.

LSEs would no longer submit their filing via Advice Letter, but instead simply create a secure FTP account with the Commission and submit files directly to a secured mailbox.

The draft would defer until phase II consideration of changing the quarterly allocation of cost allocation methodology (CAM) related RA credits to a monthly allocation as urged by the Alliance for Retail Energy Markets. Although the issue was not controversial, the ALJ cited unresolved workload issues cited by staff, and the fact that no new CAM contracts are anticipated for 2009, as justifying a lengthier consideration.

The ALJ also recommending holding review of PG&E's proposal to prevent double counting of scheduled outages in assessing the RA value of certain resources, such as QFs, until phase II. PG&E and the ISO had offered different solutions, and the ALJ was not ready to accept PG&E's as the preferred fix at this time.

N.Y. PSC Opposes Broader Buyer-Side Mitigation in ICAP Market

The New York PSC opposed the New York ISO's proposal, submitted in a compliance filing, to extend buyer-side mitigation in the ICAP market from only net buyers to any new entrant (ER08-695).

The ISO suggested the change, supported by several generators, because of the difficulty in determining whether an entity is a net buyer, as various contractual relationships and special purpose entities may be designed to avoid mitigation, and because the ISO sees little risk from applying the mitigation to all new entrants, since the worst that would happen would be offers at a competitive level (Matters, 3/10/08).

The mitigation, which FERC adopted for net buyers, is meant to prevent uneconomic entry from artificially depressing prices.

But the PSC cautioned there is risk that such a broad application of buyer-side mitigation could deter new entry.

"For example, the development of commercial demonstration projects, baseload units with lengthy development times, and other new sources of ICAP could be discouraged if it were possible that the developer would not receive any ICAP revenues because the market clearing price could fall below the bid floor," the PSC argued.

Treatment of capacity exports was another source of controversy in the NYISO's compliance filing.

Astoria Generating Company, expressing a concern raised by other generators, contended that the proposed rules regarding exports unfairly compare other, more-forward looking capacity markets to the NYISO ICAP market.

The result is an "over-simplified and unworkable" conduct and impact test for determining whether capacity exports by a pivotal In-City supplier constitute impermissible physical withholding.

The export test fails to recognize "significant" structural differences between the NYISO's monthly capacity markets and the forward capacity markets in neighboring regions, Astoria contended.

In the neighboring regions, the shortest term auctions occur four months in advance of the commitment period, are for one-year terms, primarily address balancing issues, and are thinly traded. In New York, the New York City Spot Market Auctions occur just before the commitment period, are only for one-month terms, are a primary means of acquiring capacity, and are robust.

"Given these substantial differences, the prices produced from these two types of auctions are not directly comparable," Astoria explained.

The export test also does not take into account the value of the certainty obtained by In-City suppliers from locking in capacity prices and assured revenue streams on as much as a three year forward basis for a year at a time, Astoria added.

FERC Directs NYISO to Complete ROS ICAP Analysis

Agreeing with transmission owners, FERC found that the New York ISO has not complied with all of the directives from an October 2007 order to provide a complete analysis of ICAP market withholding (including an analysis of bidding behavior) in the Rest of State (ROS) region (ER03-647-011, et. al.).

FERC had told the ISO to submit an analysis of ROS capacity offers that were not accepted by comparing the capacity offers submitted to a reasonable estimate of the resources' going forward costs.

NYISO argued that it did not have data on the going-forward costs of each ROS capacity resource and thus could not perform the study. But FERC noted in its original order that it directed NYISO to use a reasonable estimate of the going forward costs of resources whose capacity offers were not accepted.

The ISO is to submit the analysis within 60 days.

FERC agreed, though, that NYISO completed the required analysis of the quantities of ICAP that were offered but not sold, dismissing arguments from transmission owners.

NYISO did analyze the upper bound of any possible effects on prices from possible economic withholding of ROS capacity, which showed that the average monthly quantity of unsold ROS capacity has been quite small and there was virtually no unsold capacity during the Summer 2007 and Winter 2007-2008 Capability Periods, FERC noted.

Briefly:

Calif. PUC Issues Questions on CCA Bonding

The California PUC is seeking comments on the appropriate bond requirements for Community Choice Aggregators and additional mechanisms needed to ensure that bundled ratepayers are not made liable for potential costs associated with the return of CCA customers to utility bundled service as the result of a CCA's failure (R. 03-10-003). The PUC asks if CCA bonding requirements should be similar to those for electric service providers, and what is the appropriate re-entry fee for customers returning from CCAs to bundled service.

Md. PSC Sets Summer Reliability Conference

The Maryland PSC set for June 5 a legislative-type hearing on summer reliability and resource adequacy (PC14) and asked PJM, IOUs and other interested stakeholders wishing to speak to submit written comments by noon June 2.

Tenaska Buys Dynegy Peaker

Dynegy is selling the Rolling Hills peaker in Wilkesville, Ohio, to an affiliate of Tenaska Capital Management for $368 million in cash. The price works out to over $450/kW for the 815-MW (summer capacity) simple cycle, gas-fired peaker in PJM.

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MEG pointed out.

By enacting SB 1, legislators believed the Commission lacked authority to cap higher SOS rates, and expressly gave the Commission that authority for residential customers, industrials concluded. Had the legislature wanted such power to be extended to non-residential rates, it would have expressly given the Commission that power as it did for residential rates, MEG reasoned. Instead, lawmakers purposely limited SB 1 to residential rates, industrials observed.

If the Commission already possessed the authority to cap SOS rates, either through its suspension authority or just and reasonable authority, why didn't the legislature or Attorney General reach that conclusion in the lead-up to SB 1 and 2006's debate over BGE's rate hike, MEG questioned.

Even in 2007, after case 9099, the Commission determined it could not cap BGE residential SOS rates, MEG observed.

The legislature, through PUC §7-505(b)(5), also made clear that rates are to be unbundled, MEG noted, but the Commission's order violates that tenet by shifting supply-side costs to the distribution part of the bill, MEG charged.

The Commission has failed to justify that the 30% increase in non-residential distribution rates would be just and reasonable as required by PUC §4-101, MEG claimed.

The distribution charge is also a tax under Article 14 of the Maryland Declaration of Rights, MEG concluded, and thus can only be imposed by the legislature. The imposition of the charge by the Commission, therefore, violates the state constitution, MEG asserted.

The Retail Energy Supply Association argued that the opt-in rate deferral program offered by BGE to residential customers last year (rate stabilization plan II, or RSP II) is a "tried and true" mitigation method that does not impact any customers that choose not to enroll, and does not impact the competitive market.

RESA pointed out that BGE set up RSP II in just five weeks, with an order coming on May 23 and RSP enrollment lasting through June 30. That required BGE to administratively adjust some bills for customers enrolling after their bill had been issued, but that snag was outweighed, the Commission determined, by the need for customers to have adequate notice, decision-making time and opportunity to participate in such a deferral plan.

BGE's rate stabilization plan involved its full residential customer base, while a deferral plan for new Type II customers would only impact less than 10,000 customers statewide, easing the administrative burden, RESA noted. RESA therefore thinks a similar RSP could be implemented in time for new Type II customers.

RESA urged the Commission to facilitate communication to new Type II customers regarding the goals of EmPower Maryland and ways for customers to reduce consumption, especially if their quarterly market-based prices are blunted, since market-reflective rates will increase the chances of Maryland attaining the goals set forth in EmPower Maryland.

RESA also suggested that the PSC facilitate communication between retail suppliers and new Type II customers, providing customers with information such as the names, telephone numbers and website addresses of all licensed retail suppliers in a particular service territory.

The Commission could also convene a workshop for commercial customers (including all Type I customers) that focuses on customer education, with a seminar held in each utility service territory with retail suppliers setting up booths, RESA added. Commission staff would conduct the meeting and explain the various SOS pricing structures and generally how to assess individual energy usage and what to look for when shopping.