Energy Choice Matters

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O'Malley Urges PSC to Act on Rate-Regulated Generation, SOS Managed Portfolio

In a letter to the Maryland PSC, Maryland Gov. Martin O'Malley urged the Commission to order the construction of new generation on a rate-regulated basis, and to procure supplies for residential and small commercial customers using a managed portfolio. The letter was filed in Cases 9117 and 9214.

O'Malley wrote that he was "convinced" that the state must move forward with a series of industry changes that he proposed last year, but which were not enacted by the legislature. O'Malley said that, "deregulation has failed the vast majority of Marylanders who were promised lower rates and a reliable supply of electricity."

"Maryland cannot be held hostage to the failure of deregulation and broken energy markets. We can no longer afford to passively wait for competitive energy prices or pay higher incentives for merchant generation," O'Malley said.

O'Malley requested that the PSC order new generation be built in Maryland under a traditional, rate-regulated, cost-of-service basis. O'Malley cited a December 2008 report from the PSC that estimated that 1,080 MW of new generation in the state would result in $4 billion in rate reductions over 20 years. O'Malley urged the PSC to quickly act on proposals for new cost-of-service generation before it in Case 9214, and suggested that the Commission conclude the case by this summer.

Furthermore, O'Malley asked the PSC to restructure how supplies are procured for residential

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ERCOT Reports Reserve Margins Below Reliability Target Starting in 2014

ERCOT's latest reserve margin projections show higher reserve margins expected for 2010-2012, but lower margins than previously forecast for 2013-2014, including a reserve margin dipping below the 12.5% targeted for reliability starting in 2014.

Based on currently available information, ERCOT's reserve margins are forecast to remain above the 12.5% target minimum through 2013 (at 14.7% in 2013), with the reserve margin dropping below the target threshold in 2014 at 12.3%. In ERCOT's prior reserve margin forecast in May 2009, the 2013 reserve margin was projected at 16.3%, and the 2014 margin was projected at 13.9%. The current report also projects the 2015 reserve margin for the first time, at 10.2%.

This year's projections, as well as prior year projections, are listed on page 8. Despite some projected low reserve margins in prior years, ERCOT has not fallen below its target, as the market has responded with new sources of supply.

In 2014 and 2015, ERCOT said that the updated numbers reflect a net decrease of 1,105 MW in generation, primarily due to the exclusion of the Cobisa Greenville Project, a 1,792 MW natural gas-fired power plant which had been scheduled for completion in 2013. Although the project has an air permit and transmission interconnection agreement, the project developers notified ERCOT in early December that their current expectations were such that the unit should not be included in the reserve margin calculation at this time.

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Ameren Seeks Dismissal of BlueStar Rescission Period Complaint

The Ameren Illinois utilities moved to dismiss a complaint from BlueStar Energy Services regarding the rescission period contained in Ameren's utility consolidated billing and POR tariffs, arguing that Ameren's 10-day rescission period does not conflict with existing rules, and that BlueStar's complaint is procedurally improper (09-0460, Only in Matters, 10/21/09).

As only reported in *Matters*, BlueStar contended that the 10-day rescission period for mass market customers in the Ameren tariffs conflicts with 83 Ill. Adm. Code 453.40(a)(4), which BlueStar said provides for a three-day rescission period for residential enrollments executed via the internet. BlueStar noted that in accepting the POR tariffs, the Illinois Commerce Commission did not address the rescission period, but did state that only those consumer protection measures, "upon which consensus is developed in the [Office of Retail Market Development] workshops," should be included in the tariffs. Non-consensus customer protection provisions could either be submitted in a separate tariff so the Commission could suspend the disputed provisions and investigate them without delaying implementation of any consensus provisions, or the disputed protection measures could be considered as part of a formal rulemaking, BlueStar said.

Ameren countered that 83 Ill. Adm. Code 453.40(a)(4) does not conflict with its 10-day rescission period. Ameren argued that the rule is, "plainly and directly applicable to," retail suppliers, and does not serve as a restriction imposed upon the utilities' rescission periods.

Specifically, Ameren noted that the internet enrollment rules require the supplier to provide to the customer, "A conspicuous statement, within the body of the electronic version of the contract, that residential customers may cancel the enrollment within 3 business days after the Internet enrollment."

Ameren argued that the rule, "directs what statements and information must be provided by a [supplier] to prospective customers," but that, "nothing within Part 453 restricts a utility's ability to establish a rescission period allowing utility delivery service customers to call the utility and contest a notification of a supplier switch." Ameren noted that it has no means of knowing how the supplier enrolled the customer, whether it be by means of internet or otherwise.

Ameren further contended that BlueStar's complaint should be dismissed because the issue should have been raised in response to the original September 2008 tariff filing, which contained the rescission period language. "Presenting now this Complaint immediately after that proceeding has concluded is inappropriate and prejudices those parties that properly intervened, devoted their resources to informing the Commission, and offered testimony," Ameren said.

"[P]ublic policy disfavors allowing parties to wait until after resolution of suspended tariff proceedings to raise novel issues related to the approved tariffs," Ameren added.

TexRep5 Clarifies Ownership, Not Owned by Horizon Power & Light

TexRep5, LLC (d/b/a AllStar Energy, LLC) filed an amendment to its REP certificate to clarify, among other things, its parent ownership, stating that Horizon Power and Light has never owned or controlled TexRep5.

In an earlier amendment to reflect a change in ownership, TexRep5 said that Horizon Power and Light was incorrectly listed as its parent company (Only in Matters, 7/9/09). TexRep5 said that the correct parent company is the George Company.

Although there is no ownership connection, TexRep5's principals are still principals at Horizon, including Neil Leibman, TexRep5 CEO, and Tom O'Leary, TexRep5 COO.

TexRep5 is not currently serving customers.

Additionally, TexRep5 updated its certificate to reflect that it has applied with ERCOT to function as its own QSE, replacing Luminant. Luminant will still be used for wholesale supply.

TexRep5 further revised its certificate to reflect Horizon's exit from the Delaware market, under a settlement that closed a series of marketing complaints (Only in Matters, 8/19/09).

Ontario Adopts Mandatory Reporting Rules for Gas, Electric Suppliers

The Ontario Energy Board has adopted as final new mandatory reporting rules regarding contracting and marketing activity for competitive gas and electric suppliers, limiting a quarterly report on sales and enrollments to low volume customers.

As only reported by *Matters*, the proposed rules essentially impose the same obligations on competitive suppliers regardless of commodity, although contained in separate codes (Only in Matters, 9/22/09). Under the approved revisions, electric and gas retailers will be required to provide the Board with the following information quarterly, on the last day of the second month following the quarter end, for low volume customers:

a) Number of salespersons who have successfully enrolled a consumer (accepted by a distributor for flow) or successfully renewed a contract;

b) Number of new enrolments (accepted by a distributor for flow);

c) Number of contract renewals;

d) Marketing approach percentages based on new enrolments (accepted by a distributor for flow) and renewed contracts during the reported quarter, broken down by: direct mail, door to door, telesales, internet sales and other;

e) Number of consumer complaints; and

f) Retail offers available to customers during the quarter. Details include contract length and pricing details.

Although both the electric and gas rules state that the reports only relate to low volume customers (a clarification added in the final rules), subsection (f) for the electric rule retains the additional requirement that the listing of offers available must describe whether the offer was for low volume or high volume customers.

The Board also extended the compliance deadline so that the first report using these new rules shall be the report filed on or after May 1, 2010. Originally, the rules would have taken effect on January 1, 2010.

Retail gas suppliers are also required to report, on a quarterly basis, information on the total number of customers at the end of the reporting quarter who are low volume consumers (as defined in statute), broken down by the type of contract as follows:

a) Contracts with less than one year remaining in the term of the contract;

b) Contracts with greater than one year but less than three years remaining in the term of the contract; and

c) Contracts with between three and five years remaining in the term of the contract.

Electric retailers are required to report customers based on remaining contract life using the same breakdown used by gas marketers, but electric reports would not be restricted to reporting only low volume customers. However, electric suppliers would be required to separately categorize low volume consumers (less than 150,000 kWh annually) and high volume consumers (150,000 kWh or more annually), with those customers further broken down by the remaining contract life criteria listed above.

Both the gas and electric contract length reports are limited to accounts successfully enrolled (accepted by a distributor for flow).

The Board also confirmed, in response to stakeholder comment, that the rules only apply to Ontario marketing activity, but said such a clarification need not be included in the codes.

OEB declined to address Direct Energy's concerns regarding the reporting of complaints, which Direct said overstates consumer issues for retailers with large customer bases, since the complaint ratio is based on complaints versus new and renewed contracts, even though complaints may be from current, not newly enrolled or renewed, customers.

The final rules also contain various record keeping requirements related to contracts and collateral materials.

The Board's new Natural Gas Reporting and Record Keeping Requirements: Gas Marketer Licence Requirements can be found in docket EB-2009-0163. The Board's new Electricity Reporting and Record Keeping Requirements can be found in docket EB-2009-0161.

Calif. Imposes Some Utility CHP Contract Costs on Competitive Supply Customers

Electric customers of competitive suppliers and community choice aggregators will be allocated a share of the costs of the "intangible benefits" from contracts California utilities are required to sign with Combined Heat and Power facilities, under an order from the PUC (R. 08-06-024).

The Commission held that such customers on competitive supply will benefit from CHP's intangible benefits including reduced greenhouse gas emissions and locational benefits, just as bundled service customers will, and thus all customer groups should pay for such benefits. Utilities will purchase CHP output on standard or simplified contracts, with a 10 percent locational adder applied to the price of CHP systems located in high-value areas.

Specifically, competitive supply and bundled customers will be allocated the costs associated with GHG attributes and the locational premium on an equal ¢/kWh basis.

Additionally, above-market costs of such CHP contracts will be allocated to bundled customers and to customers who depart bundled service in favor of competitive supply via a nonbypassable charge.

FERC Accepts PJM Filing Removing MMU from Tariff Administration

FERC generally accepted PJM's compliance filing under Order 719 regarding PJM's proposal to move certain tariff administration functions from its external Market Monitoring Unit (MMU) to PJM, consistent with Order 719, as the Commission denied protests from the MMU, state regulators, and various load representatives. The MMU and state regulators argued that PJM's filing disrupts the terms of a prior settlement delineating market monitoring responsibilities in PJM, which resulted from a complaint filed at FERC.

FERC stressed that Order 719 holds that external MMUs are permitted only to, "provide the inputs required for the [RTO or ISO] to conduct prospective mitigation, including, but not limited to, reference levels, identification or system constraints, and cost calculations." Prospective mitigation, which FERC considers a form of tariff administration, may only be conducted by the RTO.

PJM's proposed revisions provide as required, FERC noted, that the MMU will not be permitted to participate in the administration of PJM's tariff, or conduct prospective mitigation, except that it will be permitted to provide inputs to PJM, the entity responsible for making the final determination. PJM's current tariff, which vests the MMU with prospective mitigation power, is not in compliance with Order 719, FERC confirmed.

For example, the current tariff gives the MMU final authority to determine the Equivalent Forced Outage Rate - Demand (EFORd) for a generator, which is used to determine the sell offer a mitigated generator may submit. "This provision therefore is at odds with Order No. 719 because it involves the MMU in tariff administration, by influencing a necessary determination establishing the offer a seller may bid and ultimately processed by PJM to clear the market. It also directly involves the MMU in prospective mitigation, since the EFORd determines the mitigated rate the seller may bid into the market," FERC said.

"PJM's proposed revision to Attachment DD, section 6.6(d) complies with Order No. 719. It maintains the MMUs responsibility for providing data to help determine the EFORd, but it vests the final determination of the EFORd in PJM. The revised provision states '[i]n the event that a Capacity Market Seller and the [MMU] cannot agree on the level of the EFORd, [PJM] shall make its own determination of the level of the EFORd based on the requirements of the [OATT] and the PJM Manuals,'" FERC noted.

Regarding the release of offer and bid data, the Commission directed PJM to revise its proposal such that the data is released no earlier than after four months. The MMU supports a four-month approach because knowledge of competitors' actions within a period of comparable seasonal conditions, as would occur under a three-month lag, would greatly increase the predictive value of such knowledge, and thereby facilitate anticompetitive behavior.

"We agree with the MMU that a significant percentage of market power tests involve one or more failing suppliers and indicate a significant presence of market power throughout the PJM region. By releasing data with a three-month lag period, PJM would be allowing information to be provided within the same seasonal period such that these parties could potentially ascertain the bidding behavior of their rivals and exploit market power. We also agree that a potential collusion concern exists within the PJM region," FERC said.

In its compliance filing, PJM proposed to allow aggregators of demand response to submit bids in increments of 0.5 MW. While FERC accepted the provision, it directed PJM to further justify why the current 1 MW increment threshold for bids from generators should not be revised to be 0.5 MW.

Regarding previous customer baseline revisions applicable to demand response, FERC agreed with the MMU that market participants cannot yet be confident that the demand reductions currently being credited by PJM are price-responsive reductions. The MMU had stated that PJM's existing procedures fail to ensure with sufficient accuracy that customer baseline load calculations will adequately capture end-use customer operations in a manner that will prevent demand response payments for load levels that would have occurred regardless of PJM's market opportunities. "Given these legitimate concerns, we require PJM to use its stakeholder process to develop solutions to ensure that load reductions reflect actions taken in response to price," FERC said, in directing PJM to file a status report within 90 days, along with a timeline for implementing changes.

The Commission granted PJM's request for an extension of the deadline to submit a scarcity pricing proposal until April 1, 2010. FERC's order also did not address arguments regarding PJM's Reliability Pricing Model auction protocols, and the extent to which these RPM rules may operate as a barrier to demand response participation, since the Commission has addressed such concerns in separate proceedings. Additionally, issues related to RTO responsiveness are also being addressed in another proceeding.

FERC Denies Changing Date for MISO Voluntary Capacity Auction, Citing Retail Market Impacts

FERC denied the Midwest ISO's proposal to lengthen the time, from five to ten business days before the Resource Plan Deadline, for the Midwest ISO to conduct the Voluntary Capacity Auction under its Module E resource adequacy construct, as the Commission agreed with Duke Energy that the accelerated auction would burden retail suppliers (ER10-86, Only in Matters, 10/22/09).

Duke had noted that retail suppliers enroll customers on an ongoing basis. Increasing the time between the auction and the Resource Plan Deadline would lengthen the time during which suppliers could not rely on the auction to procure capacity for new customers, since the auction will have already been completed, Duke noted.

FERC agreed with Duke. "While the Midwest ISO attempted to justify this change because it will provide more time for bilateral contracting, it has not explained why this purported benefit outweighs the harm to retail choice suppliers and other participants in the voluntary capacity auction," FERC said in rejecting the change.

The Commission accepted the Midwest's ISO proposal for clearing the auction in cases where bids and offers submitted in the auction do not meet at a single point (i.e. there is a range of cleared prices). In such situations, MISO will extend the bid curve vertically downward from its lowest bid price/quantity pair until it crosses the horizontal axis. The auction clearing price will be determined as the price of the marginal Aggregate Planning Resource Credit offer associated with the maximum amount of Aggregate Planning Resource Credit bids.

FERC declined RRI Energy's request to make MISO either determine the appropriate standard deviation that it will use to evaluate LSEs' load forecasts, or establish parameters for calculating a standard deviation to be used by all LSEs. RRI had objected to allowing LSEs to determine their own standard deviation (Only in Matters, 11/11/09).

"We agree with the Midwest ISO that the determination of the standard deviation is part of the demand forecast and, therefore, is part of the forecasting responsibility of each Load

Serving Entity - not the Midwest ISO," FERC said.

FERC rejected without prejudice the Midwest ISO's proposed language regarding must-offer provisions, as the provisions established different standards for internal and external resources. The Commission said that the same provisions must apply to internal and external resources. FERC further ordered MISO to clarify its tariff language so that it cannot be misinterpreted as creating the impression that a firm power purchase agreement with liquidated damages provisions may qualify as a Capacity Resource.

Hwy 3 MHP Submits List of Issues for NOV Docket

Hwy 3 MHP, LLC (d/b/a Etricity) filed a list of issues to be addressed at a hearing regarding PUCT Staff's Notice of Violation against the REP in connection with its 2008 default (37152).

Staff is seeking $1.44 million in penalties for alleged violations of P.U.C. SUBST. R. §25.107(f)(2), Related to Financial Standards Required for Customer Protection; §25.107(i)(8), Related to Requirements for Reporting and for Changing the Terms of a REP Certificate; §25.478(j)(2), Related to Refunding of Deposits and Voiding Letter of Guaranty, and §25.43(n)(7), Related to Transition of Customer to POLR Service.

Though the pleading was procedural and offered no substantive defenses, Hwy 3 MHP's list of issues does provide the first public look into its possible arguments. Hwy 3 MHP's list of issues includes:

- Whether certain REPs were allowed by the Commission and ERCOT to buy power and adjust their required deposits, while Hwy 3 was not provided this important option.
- Whether the monies Hwy 3 had deposited with ERCOT would have covered their power expenses to support its customer base for the two weeks Hwy 3 had requested from ERCOT to allow Hwy 3 to gather the additional requested collateral funds.
- Whether the Commission's action prevented Hwy 3 from curing the alleged violations by revoking its license based on ERCOT's inaccurate estimations of additional financial collateral requirements which were erroneously placed on Hwy 3.
- Whether ERCOT was the entity ultimately responsible for the harm Hwy 3's customers suffered by mass transitioning to POLR hastily and unnecessarily.
- Whether personnel at the Commission and ERCOT refused to assist Hwy 3 to restore its estimated financial obligations with ERCOT.

Briefly:

Md. PSC Allows All Customers at Small Utilities to Participate in PJM Market

The Maryland PSC granted permission to all retail customers in Maryland to participate in PJM demand-side management programs, including demand response programs and energy efficiency and conservation programs, without conditions, and regardless of which Maryland electric utility provides service to the retail customer. The Commission was not persuaded by Choptank Electric Cooperative's request that such permission should be limited to customers with a peak load of 20 kW or more (Only in Matters, 12/15/09). The PSC's order extends to all distribution companies, including A&N Rural Electric Cooperative and Somerset Rural Cooperative, which EnerNOC, in its petition for a PSC ruling, noted may not meet a statutory customer size threshold for PSC jurisdiction. The Commission said that should either A&N or Somerset dispute that the PSC is its Relevant Electric Retail Regulatory Authority (to which FERC grants decision-making over demand response participation at small utilities), they may apply for reconsideration.

American Transmission Systems, Inc. Signs PJM Agreement

FirstEnergy subsidiary American Transmission Systems, Inc. announced Friday that it has signed an agreement to join PJM Interconnection, a day after FERC's conditional approval of its move from the Midwest ISO to PJM (see exclusive story, Matters, 12/18/09). The integration into PJM is expected to be completed on June 1, 2011.

FERC Schedules RTO Responsiveness Technical Conference

FERC scheduled its previously announced technical conference on RTO responsiveness for February 4, 2010.

Calif. PUC Finds South San Joaquin Irrigation District's Exit Would Not Substantially Impair PG&E Rates

A final California PUC resolution finds that the South San Joaquin Irrigation District's (SSJID) proposal to provide retail electric service to existing Pacific Gas & Electric customers could raise rates for PG&E's remaining ratepayers, but "does not substantially impair PG&E's ability to provide adequate service at reasonable rates." SSJID intends to purchase PG&E's existing distribution assets and build related infrastructure to physically separate the assets from PG&E's system, in order to provide retail electric service to approximately 38,000 existing PG&E customers (Only in Matters, 11/18/09). The highest quantifiable estimate of the rate impact of SSJID's exit is $0.00032/kWh, which is 0.21 percent of PG&E's current system average rates. The estimate reflects a downward revision from the $0.00040/kWh high estimate contained in a draft PUC resolution, to account for SSJID's clarification regarding its intention to take the majority of transmission service from PG&E.

Maryland ... *from 1*

and small commercial default service customers. "The PSC should adopt a more balanced, and diversified strategy for procuring electricity for residential and small commercial customers that includes a mix of demand resources, transmission supply, regulated generation and market based short term, mid-term and long term generation contracts. A managed portfolio approach provides a hedge against future price spikes, thereby reducing price volatility," O'Malley wrote.

O'Malley also recommended using long-term contracts to procure renewable energy supplies to act as a hedge against fossil fuel commodity costs.

O'Malley listed the "reality" of deregulation as:

- "Energy generation companies have not built the new generation necessary to meet the State's growing energy needs ... [as] less than 300 megawatts of new generation has come on line. Most projects have been delayed or abandoned because of financial or commercial uncertainties.
- "The lack of in-state electric generation has constrained supply, resulting in higher electricity prices, higher congestion and capacity charges, and future reliability concerns.
- "A perverse system of capacity charges imposed by the regional transmission organization, PJM Interconnection has been created, adding hundreds of dollars to residential bills with little benefit. From 2008 to 2013, it is estimated that Maryland ratepayers will pay nearly $5 billion in capacity charges to incentivize the private sector to build new generation - enough to pay for seven new power plants - but no new generation will be built as a result of these incentives.
- "With no new generation, Maryland's power plants continue to age, posing ongoing reliability concerns. Over 67% of the State's total summer peak generating capacity is 30 or more years old.
- "Maryland now imports almost 30% of its energy from nearby states, mostly from coal-fired plants in West Virginia and the Ohio Valley. This negatively impacts the State's efforts to meet its climate goals and reduce greenhouse gas emissions.
- "Since 1999, fewer than 5% of Maryland's 2.1 million residential customers have chosen retail electricity supplier offers, much of this consisting of green choice."

ERCOT ... *from 1*

The net changes in the generation outlook since the May report show an increase in total resources for 2010, 2011 and 2012 of 1,049 MW, 681 MW and 708 MW, respectively.

Potential resources that are not included in the report's generation total include more than 3,000 MW of generation capacity which is currently mothballed but could be brought back into service at the owners' decision. Other potential resources include proposed units that have requested a full transmission interconnection study but lack either an air permit or signed interconnection agreement. The planned units under review total 2,751 MW with a 2010 in-service date, 8,704 MW for 2011 completion, and more than 20,000 MW by 2015.

ERCOT reported that more than 3,000 MW of generation has been added to the grid since May. Of the 3,140 MW of additional installed capacity, 1,689 MW is from new coal plants and 1,093 from natural gas plants.

ERCOT Projected Reserve Margins (%)

	2010	2011	2012	2013	2014	2015
May-07	8.3	6.7	5.9	n/a	n/a	n/a
Dec-07	14.0	11.2	10.5	8.2	n/a	n/a
May-08	17.3	15.0	14.5	12.3	n/a	n/a
Dec-08	21.2	18.7	17.8	17.9	15.8	n/a
May-09	20.1	18.8	17.0	16.3	13.9	n/a
Dec-09	21.8	19.9	18.1	14.7	12.3	10.2