Energy Choice Matters

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CMP Doubts Other ISO-NE Transmission Owners Would Acquiesce to "Contract Option"

Maine's withdrawal from ISO New England to pursue negotiation of a replacement plan that involves contracting with ISO-NE for most operating authority and reliability functions, "would not likely be accepted by ISO-NE, the other Participating Transmission Owners (PTOs), and, most importantly, FERC," Central Maine Power said in a report to the Maine PUC on ISO-NE reform efforts and alternatives (2008-156, Matters, 4/8/09).

Contracting for ISO-NE Operating Authority services that would necessitate changes to the transmission cost allocation and Pool Transmission Facility (PTF) revenue requirements will require, at a minimum, a supermajority of 95% of the PTO individual votes, CMP explained. CMP further noted FERC recently rejected a similar mechanism in the Midwest ISO's market services proposal.

CMP concluded that FERC would likely agree with ISO-NE members who may claim that allowing Maine utilities to access ISO-NE services at rates that do not include the costs of network transmission investments borne by ISO-NE members amounts to discriminatory treatment.

"Withdrawal from ISO-NE will require the development of a detailed alternative plan for the operation of the electric grid and wholesale power markets that first must be approved by FERC before implementation; this process will be time-consuming and cause significant regulatory uncertainty in the near term and in all likelihood result in an inferior market structure and seams in the long term, which in both respects will undermine Maine's efforts to encourage renewable development in the State," CMP added.

ISO-NE has said it is not inclined to undertake a review of the complex and interwoven regional

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Texas House Bill for Retail Market Monitoring, Disconnection Prohibitions Advances

The Texas House State Affairs Committee voted out a wide-ranging bill (HB 3245) that would create a retail market monitor, strengthen disconnect prohibitions, and implement other consumer protections. Though voted out in late April, substitute committee language was not printed until Friday.

The bill would require ERCOT to contract with an entity selected by the PUCT to act as the Commission's retail electric market monitor, which is to be charged with detecting and preventing market manipulation strategies and unfair, misleading, or deceptive practices. The retail monitor would also recommend measures to enhance the efficiency of the retail market.

The Commission would define the exact scope of the monitor's duties by rule, including rules to clearly separate the policymaking responsibilities of the Commission, and the monitoring, analysis, and reporting responsibilities of the retail monitor.

The bill would also give the Commission explicit investigatory authority over retail prices and REP practices. Similar to other bills which have advanced, HB 3245 would also permit the PUCT to order refunds in cases of market power abuse (see below).

HB 3245 would also expand disconnection protections, similar to other bills which have advanced. From July 1 through September 30, REPs would be prohibited from disconnecting (or ordering a disconnect for) low-income customers, low-income seniors, and critical care customers, under various provisions.

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Connecticut Energy Board Sees No Immediate Need for Procurement Through IRP

Connecticut is expected to have sufficient resources to meet reliability requirements for several years, the Connecticut Energy Advisory Board said in its analysis of the utilities' integrated resource plan, as it submitted a modified plan to the Connecticut DPUC.

Accordingly, CEAB recommended that no procurement actions be taken at this time. CEAB also said that it has not yet developed an analysis to demonstrate under what circumstances procurement should be undertaken to implement policy goals (e.g. lower costs or environmental benefits), rather than to simply ensure reliability, as set forth in a recent DPUC decision (Matters, 2/20/09).

The CEAB did not modify several recommendations made by the utilities with respect to long-term contracts for renewables in forwarding the IRP to the DPUC, although it said its action does not constitute approval or endorsement of all facts contained in utilities' IRP, which will be examined more thoroughly in the 2010 plan.

As was the case in last year's IRP, the utilities again argued that long-term procurements of bundled RECs, energy and capacity could produce lower REC prices for customers, and also help break the link between retail rates and wholesale prices driven by marginal gas-fired plants.

While the utilities conceded that their analysis does not demonstrate with certainty that long-term renewable contracts will reduce the cost of RPS compliance, they contended that long-term contracts with appropriate pricing mechanisms would be almost certain to reduce the volatility of REC prices and encourage development of new renewables, which would improve the supply/demand balance, and reduce market REC prices. "In other words, while there is no guarantee that such contracts will result in compliance costs that are lower than prevailing spot prices for RECs in every year, they will ensure that the worst case, compliance at the [alternative compliance payment] cost, does not occur," the utilities said.

The utilities also suggested that utility-owned renewable generation may be required to meet renewable targets, especially if merchant renewable developers eschew long-term contracts that approximate their cost of service due to higher price signals in the forward market. Utility-owned backstop projects would put competitive pressure on the REC markets, utilities said, and encourage developers to seek long-term contracts.

Elkton Gas Says RM 35 Provisions Should be Optional for Small LDCs

Costly upgrades required for Elkton Gas to comply with proposed Maryland requirements for utility consolidated billing and first-of-the-month enrollments at gas LDCs means that customers would be better off if Elkton discontinued its current transportation service offering, rather than implement the costly changes needed for compliance, Elkton said in comments to the Maryland PSC.

Elkton has 6,250 customers, of which 5,730 are residential and 520 are commercial and industrial. It has offered a transportation service option for C&I customers for over seven years with no enrollments on third party suppliers. It currently does not offer residential choice, and Elkton said the enrollment and billing proposals contained in RM 35 would make expansion of choice to residential customers cost prohibitive.

Utility consolidated billing would cost $750,000 to $1 million to implement, Elkton estimated, or $1,500-$2,000 per commercial customer. First-of-the-month enrollment would cost even more, Elkton said.

Given the lack of supplier interest in its territory, Elkton asked that small LDCs be permitted to choose whether to implement utility consolidated billing and first-of-the-month enrollments.

PUCT Staff Says ERCOT Congestion Zones Resulted from Proper Procedure

ERCOT's assignment of AEP Energy Partners' Oklaunion plant to the West congestion zone resulted from the proper procedural and substantive application of the ERCOT Protocols, PUCT Staff said in a statement of position (36416).

The process used by ERCOT involved remanding the zones to a joint Wholesale Market Subcommittee-Technical Advisory Committee meeting. Although Staff noted the usual process is sequential, Staff said joint meetings have been utilized previously in order to accommodate time constraints, citing June's joint WMS-TAC meeting to address the shadow price cap level, a point raised in ERCOT's testimony (Matters, 5/1/09).

Staff also said leaving Oklaunion in the West zone does not require the coal plant to vary its output.

Echoing concerns raised by Luminant, Shell Energy North America urged the PUCT not to change the congestion zones. Shell said it has arranged to supply its retail customers in accordance with the zones adopted by ERCOT for the 2009 calendar year, noting a change will make certain transactions uneconomic.

"It is important for the market to have certainty so that the bilateral transactions which are used to both hedge and supply the great majority of the needs of retail electric providers ('REPs') to serve their customers are not put in jeopardy. In addition, making changes of this magnitude in the middle of the year will destroy confidence in the bilateral markets for the future," Shell said.

Higher 2008 BGS Auction Price Fuels Growth at PSEG Power

PSEG Power, consisting mostly of merchant assets in PJM, announced higher operating earnings of $359 million for the first quarter of 2009 compared with operating earnings of $279 million a year ago.

The Power unit benefited from the rolloff of the 2005 New Jersey BGS auction contract priced at $65.41/MWh, which was replaced with the 2008 contract priced at $111.50/MWh.

Margins were also higher due to the re-pricing of a below market, round the clock wholesale contract for 500 MW which expired at the end of 2008.

These higher prices, as well as lower costs, improved Power's gross margin for the quarter to $63/MWh from $51/MWh a year ago. PSEG Power is maintaining its forecast of $57-58/MWh gross margins for the calendar year, as similar improvements in year-over-year pricing are not expected in future quarters.

Net income at PSEG Power, which includes mark-to-market and decommissioning impacts, was $318 million versus $275 million a year ago.

PSEG Energy Holdings, which includes Texas merchant assets, reported lower operating earnings of $4 million versus operating earnings of $28 million in the year-ago quarter. Lower gas prices reduced the profitability of the unit's combined cycle gas assets in Texas, which remains a "difficult market." The unit expects challenging market conditions in Texas for the gas-fired assets, with a decline in power prices and spark spreads year-over-year, to continue through subsequent quarters.

Net income at Energy Holdings was $7 million versus $42 million a year ago.

Briefly:

Constellation Settles with TRE Over Generator Operator Designation

Constellation Energy Commodities Group has agreed to pay $5,000 to resolve a dispute with the Texas Regional Entity regarding CECG's registration on the NERC compliance registry as a Generator Operator due to a tolling agreement with Power Resources, which owns a 212-MW, gas-fired, combined cycle generator in Howard County, Texas (Matters, 11/21/08). CECG acts as a Level 4 QSE for the plant under the tolling agreement. CECG initially protested the registration, since it has no operational control of the plant, but subsequently entered into a Joint Registration Organization (JRO) with Power Resources, which delineates each party's responsibility with respect to reliability standards compliance. Constellation will withdraw its appeal of its compliance registration designation under the settlement, which is subject to FERC approval.

TXU Offering Voluntary Disconnect Moratorium for Summer

TXU Energy said it is again instituting a voluntary moratorium on summer disconnections for customers designated as low-income, ill or disabled, or who are at least 62 years of age. TXU will also offer more flexible deferred payment plans to these customers. The measures will be in effect July 1 through September 30, 2009. TXU will also waive deposit requirements for residential customers who are at least 62 years of age and for all customers with a good record of timely payment. Customers that are low income or at least 62 years old must enroll in a deferred payment plan with an upfront payment of 25%, with the balance paid over five additional installments, to avoid disconnection. Customers who are both low income and seniors, or to whom disconnection would cause serious illness, will not be required to make a payment at the start of the deferral program.

N.Y. PSC Extends Comment Deadline on NYSEG/RG&E Phase II Nonbypassable Charge Issues

The New York PSC said the deadline for submitting comments on Phase II issues related to NYSEG's and Rochester Gas and Electric's petition to adjust their nonbypassable charges, in light of the discontinuance of the fixed price option, has been extended to July 1 (Matters, 3/9/09). Phase II includes proposals to modify the inputs used for the variable supply charge and nonbypassable charge for the period staring January 1, 2010.

Entergy Merchant Earnings Down on Outages

Net income at Entergy's competitive business segment was down for the quarter at $175 million versus $213 million a year ago, due to longer refueling outages in the current period. Entergy said that today's environment is more ripe for potential acquisition opportunities, but stressed that on the merchant side, it is not currently in active discussions with any party on a transaction. While Entergy has "scrubbed the market," it hasn't found any assets that would meet its rigorous financial test for a combination.

Iowa Muni to join MISO

Iowa’s largest municipal electric utility Muscatine Power and Water intends to join the Midwest ISO on Sept. 1, 2009, as a transmission-owning member. Muscatine has contracted with Tenaska Power Services to conduct all Midwest ISO commercial activities as its agent. Muscatine operates three coal-fired electric generating facilities with a combined capacity of nearly 300 MW.

Maine ... *from 1*

arrangements required for Maine's exit absent "broad stakeholder support," which, as evidenced by a recent response from NEPOOL Participants, is unlikely, CMP said.

Maine's wind resources would be particularly harmed if Maine were unable to negotiate access to ISO-NE's energy and capacity markets, as the ISO's day-2 markets alleviate many challenges associated with intermittent power since the day-2 markets do not require firm transmission schedules, CMP reported.

Ultimately, CMP said, withdrawal from ISO-NE will not produce lower costs for Maine customers, and instead will expose them to the likelihood of increased rates. CMP found no basis to assume that Maine ratepayers would pay less for the discrete services that ISO-NE provides on a contract basis, and warned that Maine ratepayers will be responsible for 100% of the necessary transmission upgrades in Maine.

An analysis conducted by CRA International for Bangor Hydro-Electric pegged transition costs at $10-15 million to move to an ISO-NE contract option, with annual costs of $2-4 million (not including charges to participate in ISO markets), plus an undetermined exit fee. The transition would take at least 16 months, assuming FERC does not set formal hearings on the plan.

Furthermore, requiring CMP and Bangor Hydro-Electric to perform their own transmission planning will likely result only in a transfer of responsibility and cost to the utilities, with no meaningful change in the planning criteria used to determine if projects meet all applicable NERC, NPCC and ISO-NE reliability standards, CMP said. ISO-NE would likely remain as the Planning Coordinator, and it is therefore unlikely that ISO-NE would consent to adoption of drastically different planning standards for Maine than for the rest of the region, CMP explained.

CMP reiterated, as detailed in its previous report, that meaningful reforms have been achieved in the areas identified as deficient in the PUC's January order, including reforms regarding governance and transmission cost estimates.

Texas ... from 1

Disconnection of low-income customers during the summer period would be prohibited if the customer requests and complies with the terms of a deferred payment plan under which the customer pays a minimum of 33% of the outstanding balance due, and pays the balance over the next five billing cycles. Customers would be eligible for the plan if they do not owe an outstanding balance from a previous deferred payment plan. Customers could subsequently continue to avoid disconnection by paying 33% of the balance currently due and agreeing to pay the recalculated remaining balance in equal installments over the next five billing cycles.

Low-income customers 65 years or older could avoid disconnection during the summer period by agreeing to a deferred payment plan with no payment due until after September 30. A minimum of 25% of the balance would be due in the first installment due after September 30, with five additional installments required.

Critical care customers could not be disconnected anytime during the summer period, without the requirement that the customer enter a deferred payment plan.

The summer disconnection provisions would not apply to residential prepaid metered service, but the law would also hold that critical care customers are not eligible for metered electric service sold on a prepaid basis.

The bill also redefines conditions constituting a weather emergency triggering various disconnection prohibitions. Under the bill, a weather emergency would include a day for which the National Weather Service forecasts that the heat index will reach or exceed 105 degrees Fahrenheit in any part of a county in the relevant service area, or the two days following the observance of such a heat index. That language expands the current definition which relies on the NWS issuing a heat advisory, rather than merely forecasting a specific index. The new language also triggers the moratorium if only a subset of a county sees the heat index forecast, as opposed to the entire county under the current language.

HB 3245 would also provide that ERCOT shall not pass through to retail customers or retail electric providers a cost or charge associated with nodal wholesale market design implementation.

The PUCT would also be required to post on Power to Choose charts or a link to a comparison of the prices of natural gas, real-time or balancing electric energy, and retail electricity. The data would be updated every business day that the Commission is open.

Senate Passes Market Power Refund Bill

The Texas Senate unanimously passed SB 1772 which would give the PUCT the ability to order restitution in cases of market power abuse (Matters, 4/27/09).

SB 1772 would allow the PUCT to order a party found to have committed market power abuse to refund monies to the parties directly affected, in lieu of assessing an administrative penalty. The refunds could not exceed the greater of the administrative penalty that would otherwise have been ordered by the Commission, or 115% of the amount of additional profit that the party received as a result of the market power abuse.

The bill also authorizes the Office of Public Utility Counsel to intervene in market power abuse cases. However, the bill was amended on the floor to strike portions of the committee's language which would have given the PUCT discretion to allow other affected parties to intervene as well. All affected parties will still be permitted to intervene in the subsequent docket initiated by the PUCT to distribute the refunds.

The bill now moves to the House.