Energy Choice Matters

June 15, 2009

DPU Does Not Impose Up-Front Election on Long-Term Renewable Contract Cost Recovery

The Massachusetts DPU declined to adopt narrower parameters regarding electric distribution utilities' cost recovery of long-term renewable contracts, stating that its adopted rules are meant to preserve flexibility in the contracting process (08-88, Matters, 5/11/09).

As required by the Green Communities Act, the DPU established rules mandating that each distribution company shall conduct at least two separate solicitations for long-term contract proposals from renewable energy developers during the period from July 1, 2009 through June 30, 2014. Distribution companies are not required to enter into long-term contracts exceeding 3% of their annual load in the aggregate. Utilities may voluntarily solicit additional proposals as well.

"The Department's objective is to avoid predetermining or limiting the consideration of proposed contracts or evaluation models in advance," the DPU said in its order.

"Instead, the Department will make fact-based decisions on a case-by-case basis in order to maintain sufficient flexibility in reviewing long-term contracts for renewable energy."

One of the areas in which the DPU declined to provide additional requirements was cost recovery. As proposed, utilities will be permitted a choice in cost recovery: (1) selling energy to basic service customers, with RECs applied toward meeting their RPS; (2) selling energy and RECs into the market with associated debits/credits applied to all distribution customers via nonbypassable charge; or (3) an alternate approach subject to DPU approval.

Competitive retailers had urged the DPU to require the distribution utilities to make the election of the cost recovery method up-front, for the life of the contract, to avoid potential gaming under which contracts could be applied to basic service customers' benefit when below market, but changed to apply to all distribution customers when above-market (Matters, 4/20/09). The Department declined to add any such requirement.

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Maine PUC Allows Renewal of CMP, BHE Transmission Owner Agreements with ISO-NE

The Maine PUC will allow the automatic two-year renewal of Central Maine Power's and Bangor Hydro-Electric's transmission owner agreements with ISO New England, finding that remaining in ISO-NE with the reforms achieved to date is a superior vehicle to achieve the state's energy objectives than the alternatives presented (2008-156, Matters, 6/9/09).

The utilities were directed to continue to aggressively pursue reforms at the ISO as well.

Alternatives considered by the PUC, including leaving the ISO but contracting with it for specific services, as well as creating a Maine Independent System Administrator, would not provide cost savings to Maine's ratepayers, the Commission said.

Areas of concern for the PUC in current ISO-NE structure include transmission cost allocation and cost-effectiveness, and the lack of a consumer-focus in governance.

Despite those concerns, hearing examiners concluded that the seams created by leaving ISO-NE would reduce efficiency, and also said that the simplified, day-1 market under a Maine Independent System Administrator would discourage demand response and wind generation.

FERC Waives Refunds Prior to Nov. 5, 2007 in RSG Rate Mismatch Case

FERC exercised its discretion to waive refunds of Revenue Sufficiency Guarantee charges related to the "rate mismatch" issue in docket EL07-86-005 (et. al.) for the period April 25, 2006 through November 4, 2007, in an order dismissing rehearing requests of its November 7, 2008 Fourth Rehearing Order.

The order comes in the Commission's tortuous proceeding addressing whether there is a mismatch between the numerator and the denominator of the rate formula used to calculate Revenue Sufficiency Guarantee charges in the Midwest ISO, due to what types of virtual offers are included in each. In its Second Rehearing Order, FERC had said there was, in fact, a rate mismatch, but later said there was no mismatch in its Second Compliance Order (issued November 5, 2007). In its November 7, 2008 Fourth Rehearing Order, FERC called its earlier statement in the Second Rehearing Order that a rate mismatch existed an "error."

FERC denied requests to defer resettlement of Revenue Sufficiency Guarantee charges related to the Fourth Rehearing Order order.

However, in light of the confusion created by the Second Rehearing Order, FERC decided to waive the refunds for the period from April 25, 2006 through November 4, 2007 (and clarified that earlier periods are not subject to refund), since FERC did not address the rate mismatch issue comprehensively until the Second Compliance Order issued on November 5, 2007.

Refunds will be required from November 5, 2007 forward, with applicable interest as required under Commission regulation.

CenterPoint Files to Lower Some Discretionary Service Charges

CenterPoint Energy filed at the PUCT to reduce several of its meter-related Discretionary Service charges to reflect the progressive reduction in costs resulting from advanced meter deployment. Charges are only lower for services for premises with (or planned to have) activated remote connect capability; charges are unchanged for poly-phase and >200 amp meters.

Proposed Changes (for meters with or planned remote connect capability)

Charge	Existing	Proposed
DCS.1 Standard Move-In	$16.00	$14.86
DCS.2 Priority Move-In	$42.00	$38.53
DCS.5 Disconnect for Non-Pay (DNP)		
Standard Disconnect at meter	$9.00	$8.45
DCS.6 Reconnect After DNP		
Standard Reconnect	$10.00	$9.33
Same Day Reconnect	$35.00	$32.07
Weekend	$35.00	$32.07
Holiday	$159.00	$144.72
DCS.8 Re-Reads		
Meter Reading found to be accurate (non-IDR)	$6.00	$5.56
DCS.9 Out-of-cycle Meter Read for the Purpose of a Switch		
Non-IDR	$6.00	$5.51

Md. PSC Orders Pepco Utilities to Fix SOS Bid System

The Maryland PSC ordered Pepco and Delmarva Power & Light to have their system used for the SOS bidding process either repaired, upgraded or replaced to eliminate the difficulties noted by the Commission's bid monitor during the June 8 solicitation (Only in Matters, 6/11/09).

The Commission's bid monitor had reported that for the PHI utilities, at times, the price reported on a summary level differed from the actual bids on the submitted bid form spreadsheets. The PHI utilities' system also suffered through periods where it slowed to an "intolerable" level, the bid monitor said.

Pepco and Delmarva have begun to take corrective action, and were directed to make regular reports to the Commission's Technical Staff on the companies' progress, including the date of the successful completion of the efforts.

The Commission also accepted the winning bids for all 26 blocks of power offered in the June 8 solicitation, which included Type II load for all utilities, plus two blocks of residential load at Allegheny Power and one block of Type I commercial load at Baltimore Gas and Electric.

ERCOT Discloses ESI IDs to Wrong Market Participant

An ERCOT Retail Account Manager inadvertently included an incorrect Market Participant on an email distribution relating to a transaction processing error, and in doing so disclosed one Load Serving Entity's ESI IDs for 175 retail transactions to another Market Participant, which is protected information under the Protocols, ERCOT reported in a notice of Protocol violation at the PUCT.

The disclosure, due to human error, occurred on May 28, as ERCOT was informing market participants of transaction processing failures due to ERCOT reaching its 1 billionth transaction, which caused a mapping failure because the 10 digits were too large for the 9-digit column used in the process.

ERCOT said that it has reset the counter, and has implemented additional procedures to ensure that the transaction process counter will not exceed 999,999,999 in the future.

Separately, the recent disclosure of the 2008 aggregated Adjusted Metered Load (AML) data for each Retail Electric Provider to a Market Participant (Matters, 6/4/09) engendered discussion at the recent Technical Advisory Committee meeting, with ERCOT responding to such discussion with the following actions:

• ERCOT will continue to provide additional training to departments involved in market information requests to prevent additional inadvertent disclosures of protected information;

• ERCOT will emphasize the handling of Market Participant inquiries through ERCOT Client Services to promote the consistency in the management of inquiries regarding protected information. Recurring internal communications will stress this practice;

• In the event of a disclosure, ERCOT will request of each Market Participant who inadvertently receives protected information to provide in writing, on company letterhead, that the protected information was deleted and properly destroyed from all company records; and

• ERCOT will broaden the number of email exploder lists receiving notices of the disclosure of protected information to include TAC and TAC subcommittee lists.

FERC Approves Day-Ahead EDR Offers, Orders Transition Period for Use of XML

FERC conditionally approved the Midwest ISO's tariff changes to permit day-ahead Emergency Demand Response (EDR) offers, but directed MISO to develop a transition period to allow load resources to develop the capability to receive instructions via Extensible Markup Language (XML) (ER09-991, Matters, 4/15/09).

Previously, MISO required Emergency Demand Response offers to be made at least 30 days in advance, and for offers to be for 30 days. The approved changes allow Emergency Demand Response offers to be made no later than 1100 EST on the day prior to the next operating day, and permit resources to offer emergency demand response for a single day.

The only contested part of MISO's filing was the requirement that participants receive dispatch instructions via XML. Certain large customers, such as Alcoa, protested the cost of XML, especially for new load resources, and argued that other RTOs allow phone or email dispatch (Matters, 5/6/09).

FERC, however, approved the XML requirement, agreeing with MISO that timely Emergency Demand Response dispatch is critical for reliability reasons. The Commission declined to overrule the MISO's judgment that the phone call process permitted in PJM would not work with the unique nature of the Emergency Demand Response program.

The Commission did require MISO to grant load resources additional time to implement XML systems, directing the ISO to develop alternative procedures and a transition program that provides Emergency Demand Response participants with a reasonable amount of time to obtain the necessary equipment and train personnel. FERC did not set a timeframe for the transition period, but ordered MISO to submit a compliance filing outlining such alternative procedure to be in place for a "reasonable" amount of time.

New England Capacity Importers Move to Dismiss Conn. Complaint

Several New England capacity importers moved to dismiss an amended complaint from Connecticut load representatives that alleged sellers engaged in a high-offer strategy to avoid dispatch while collecting transitional capacity payments, citing the complaint's lack of evidence and reliance on conjecture and conclusory statements (EL09-47, Matters, 5/29/09).

Constellation Energy Commodities Group, one of three sellers identified in the complaint (in addition to unidentified sellers), argued that the sole "factual" support for the amended complaint is an affidavit filed on by the load representatives which is, "replete with conclusory statements, speculation and conjecture, and lacks sufficient facts to support the allegations contained in the Amended Complaint."

"[T]he Commission has long recognized that mere conclusions and allegations without factual support are insufficient to support a complaint under Section 206 of the FPA [Federal Power Act]," Constellation said. Moreover, ISO New England has clearly stated that no tariff violations occurred, and that the Northern New York capacity resources met their obligations under the ICAP import rules, Constellation added.

The complaint amounts to a collateral attack on FERC's approval of the transition payment mechanism under the Forward Capacity Market settlement, which was accepted as just and reasonable, Constellation said.

H.Q. Energy Services (U.S.), another seller named in the complaint, added, "It appears that the real goal of the Complaint is to have the Commission grant Connecticut's request for a Section 206 proceeding in which Connecticut can then raise issues of market manipulation under FPA Section 222, thereby hoping to show that fraud had been perpetrated on consumers and that refunds for capacity payments should be ordered retroactively to the commencement of the FCM transition period in 2006."

HQUS also suggested that the only reason for the continued complaint, in light of the ISO's clarification that no withholding occurred, is so that the Connecticut parties may pursue a fishing expedition on the sellers' data.

HQUS said that it did not engage in the high-offer strategy hypothesized by Connecticut, and reported that its hourly average energy offers were below the threshold that Connecticut itself identified as "competitive" some 95% of the time.

An allegation of collusion -- based on solely on one employee changing jobs from one seller to another -- is insufficient by any conceivable standard for pleading a conspiracy or fraud, HQUS added, calling the allegation, "baseless, and shameless."

Northeast Utilities, however, lent support to the Connecticut parties, stating, "a full review of the facts is warranted by the Commission in order to preserve the integrity of the New England capacity market and fashion appropriate remedies where necessary."

AEP Utilities Call OCC Simply Wrong on Ormet Delta Revenue Claims

The Ohio Consumers Counsel and several large customers are "simply incorrect" in alleging that Columbus Southern Power and Ohio Power are collecting delta revenues associated with a temporary arrangement which provides discounted generation to Ormet, the AEP utilities said in an answer at PUCO.

OCC had alleged that the AEP companies were collecting delta revenues from the Ormet temporary arrangement in their current electric security plan rates, and have collected $12 million to date (Matters, 6/8/09).

However, the AEP companies said that the Ormet delta revenues are being deferred on the companies' books for future recovery as authorized by the Commission.

"There is nothing to refund. There is no action by the Companies from which they should cease and desist ... No such revenues have been collected," the AEP utilities said.

AEP argued OCC apparently has confused the revenue reduction associated with the expiration of the 2007-2008 Ormet special contract, which was reflected in the average 2009 generation rates authorized by the Commission, with the delta revenues associated with the Ormet temporary special arrangement which became effective in 2009.

33% RPS in Calif. Would Cost $115 Billion in Capital Investment

Reaching a potential 33% RPS target by 2020 would require $115 billion in capital investment (transmission and generation), versus $52 billion required under the current 20% mandate, California PUC Staff said in a report.

Total statewide electricity expenditures in 2020 under a 33% RPS would be $54.2 billion, compared with $50.6 billion under the 20% target, and $49.2 billion if all new generation were gas-fired. Those expenditures translate into an average retail price of $0.169/kWh under a 33% RPS, $0.158/kWh under a 20% RPS, and $0.154/kWh under an all-gas scenario.

Staff noted California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission, which poses a risk that certain resource zones may fail to develop. Even though a 33% RPS scenario relying on distributed generation would cost the most of all scenarios studied ($58.0 million or $0.181/kWh), Staff said that the state should consider a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources, with procurements tailored to resources that are not dependent on new transmission, such as distributed solar photovoltaics.

Briefly:

Maryland Moves to Dismiss Constellation Appeal

The State of Maryland plans to file a motion to dismiss Constellation Energy's appeal of the PSC's order holding that Commission approval is required for EDF's 49.99% investment in Constellation's nuclear group (Matters, 6/12/09). Deputy Attorney General John B. Howard Jr., said that an appeal was impermissible until the PSC concludes its investigation. Meanwhile, Gov. Martin O'Malley renewed calls for a one-time 10% credit in annual Baltimore Gas & Electric rates as a condition of the EDF transaction. Additionally, the House of Delegates Economic Matters Committee will hold a meeting on June 16 as part of the normal course of gathering facts and testimony prior to next year's session, and electricity re-regulation will be among the primary topics.

Nordic Energy Services Seeks Mich. Electric License

Nordic Energy Services, LLC applied for an alternative electric supplier license in Michigan. Nordic Energy Services says it has a contract with ACES Power Marketing to provide 24-hour scheduling, operations support, and risk management services, and relies on EC Infosystems for Electronic Data Interchange services.

Glacial Receives Expanded Maine License

The Maine PUC granted Glacial Energy's request to expand its electric supplier license to include small commercial customers in addition to medium and large non-residential customers at Central Maine Power Company, Bangor Hydro-Electric and Maine Public Service.

Exelon Plans 1.5 GW in Uprates

Exelon announced plans for power uprates across the company's nuclear fleet that will generate between 1,300 and 1,500 MW of additional generation capacity within eight years. The project commenced with a completed 38-MW uprate at Exelon's Quad Cities nuclear plant near Cordova, Ill. Uprate projects are underway at Exelon's Limerick and Peach Bottom nuclear stations in Pennsylvania and the Dresden, LaSalle and Quad-Cities plants in Illinois. Those are expected to produce nearly a quarter of the new megawatts.

ERCOT Holds Wind Workshop

ERCOT will be hosting a wind workshop on June 26 to discuss the Low Voltage Ride-Through (LVRT) Study and the wind forecasts that are being produced by AWS Truewind for ERCOT.

Mass. Contracts ... from 1

As proposed, distribution companies will be required to "coordinate" with the state's Department of Energy Resources in designing their solicitations, and must "consider" participating in a DOER-administered solicitation process prior to conducting their own procurements. However, utilities may conduct their own solicitations upon DPU approval, with the Department clarifying in its final rules that utilities must seek approval of any solicitation prior to its use.

Solicitations are not limited to competitive RFPs, and may include individual negotiations, or other methods. Distribution companies may contract for energy only, RECs only, or for both.

A distribution company's obligation to enter long-term contracts is separate and distinct from its obligation to meet RPS requirements. The rules governing long-term renewable contract solicitation will not limit consideration of other short- or long-term contracts for power and/or RECs submitted by a distribution company for review and approval by the Department.