Energy Choice Matters

August 20, 2009

PUCT Staff Recommends Denying Twice Annual TCOS Petition; Favors Broader Rulemaking

PUCT Staff have recommended that the Commission deny a petition for rulemaking from several Transmission Service Providers to allow updates to the interim transmission cost of service (TCOS) rate twice annually, rather than once annually. Instead, Staff suggested opening a rulemaking project to address not only the relief sought by petitioners, but other closely related issues to allow for a more complete assessment.

Staff said that the petition, as filed, frames the issues too narrowly and does not adequately address related considerations such as (1) the utilities potentially having an open-ended ability to place into ratebase large amounts of capital investment and obtain administrative approval of rate increases without any corresponding requirement to file for a full rate review after some prescribed period of time, and (2) the reduction in regulatory lag that would result from implementation of the petitioners' request and the concomitant impact on the utility's financial risk and return on equity.

Staff said that the new project would seek to balance those concerns with the relief sought by petitioners.

Reliant Energy Retail Services urged that if the Commission, as suggested by Oncor, also allows more frequent adjustments to the transmission cost recovery factors (TCRF) charged to REPs, the impacts and logistics for REPs must be considered. As only reported by *Matters*, Oncor said that more frequent TCOS filings should be accompanied by more frequent TCRF filings to prevent regulatory lag experienced by distribution service providers.

Reliant noted that because of backoffice logistics, as well as customer disclosure rules, REPs can not immediately pass through an adjustment to the TCRF to retail customers. In particular,

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Smitherman Cites Cost Concern on Nodal Parking Deck Projects

Chairman Barry Smitherman said that the PUCT and stakeholders must seriously consider costs of nodal project add-ons that are not implemented upon the go-live date, which will be housed in a "parking deck" whose creation was approved by the ERCOT board Tuesday.

What the parking deck will contain is itself subject to disagreement. The parking deck will house Nodal Protocol Revision Requests (NPRRs) that cannot be implemented prior to the market go-live date. One category of such NPRRs are market enhancements that improve the existing nodal protocols.

However, some stakeholders, such as the South Texas Electric Cooperative, are concerned that other NPRRs will not be actual enhancements, but rather protocol revisions required due to a disagreement between ERCOT's interpretation of the current protocols and what stakeholders intended when drafting the protocols. Similarly, some stakeholders are concerned that the protocols may not synch with the functionality of the nodal systems, requiring NPRRs to correct such situations -- a concern raised by the Texas Energy Association for Marketers. If NPRRs under either case are placed in the parking deck, a contingent of stakeholders argued that the nodal market implemented upon go-live will not be the design which was originally contemplated as being built

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DPUC Adopts REC Banking Rules

The Connecticut DPUC adopted rules to allow retail suppliers and utilities to bank RECs under the terms proposed in an earlier draft (Matters, 8/13/09). The Department intends to submit the regulations to the Legislative Regulation Review Committee on October 2, 2009.

As only reported in *Matters*, the banking rules permit load serving entities to bank RECs for up to two years, if that LSE has historically complied with the renewable portfolio standard through either RECs or alternative compliance payments. Earlier drafts would have only permitted banking by LSEs who used RECs exclusively to meet their past RPS obligations (Matters, 6/8/09), but the DPUC expanded the eligibility criteria.

Banking will be limited to 30% of an LSE's required RECs in a given class of renewables.

FERC Sets Paper Hearing on Dominion FCA De-List Protest

FERC instituted an expedited paper hearing process to hear Dominion Resources Services' protest regarding ISO New England's rejection of Forward Capacity Market de-list bids submitted by Dominion's Salem Harbor units, finding that neither Dominion nor ISO-NE has justified their proposed de-list bid levels (ER09-1424).

ISO-NE rejected the Salem Harbor units' de-list bids due to the allocation of the station's common costs to each unit, and due to issues at each specific unit relating to the appropriate length amortization and treatment of the Peak Energy Rent and infra-marginal revenue. ISO-NE instead accepted alternate de-list bids developed by the market monitor which ISO-NE said were required to prevent over-payment due to Dominion's proposed allocation of common costs. Dominion applied all common costs of the Salem Harbor Station to each unit's Going Forward Costs, while the market monitor determined the Going-Forward Costs of various multi-unit combinations. The market monitor also used a seven year (or longer for one set of capital costs) amortization period, versus three years as used by Dominion.

FERC found that ISO-NE has failed to provide sufficient cost support for the market monitor's alternate bids with regard to both the common costs issue and the unit-specific issues. However, FERC held that Dominion has similarly failed to support its assertions regarding the market monitor's de-list bids.

"In particular, ISO-NE has stated, without contradiction by Dominion, that if more than one of the Salem Harbor units receives a Capacity Supply Obligation on the basis of the de-list bids submitted by those units, Dominion would over-recover its common costs, and Dominion has failed to demonstrate why, in that circumstance, such over-recovery would not be unjust and unreasonable," FERC said.

While Dominion argued that the ISO-NE tariff does not contain any provision allowing the ISO to address the treatment of costs that are common to multiple resources, FERC held Dominion's argument is irrelevant now that the case is before the Commission, which retains the authority, regardless of ISO-NE's tariff authority, to determine whether the de-list bids are just and reasonable under section 206 of the Federal Power Act.

The Commission set an expedited paper hearing schedule so that the de-list bids can be determined prior to the October 5, 2009 Forward Capacity Auction.

FERC also stated that it intends for any order to be limited to the Salem Harbor units. The Commission directed ISO-NE to work with its stakeholders to develop tariff provisions that explicitly address ISO-NE's treatment of similar common cost situations prior to the October 2010 Forward Capacity Auction to avoid a repeat of the controversy presented in the instant case.

American Municipal Power Seeks Exception to MISO Interchange Schedule Proposal

American Municipal Power asked FERC to carve out an exception to the Midwest ISO's proposed tariff revisions to clarify the timeline for submitting Interchange Schedules, arguing that MISO's proposal is too restrictive (ER09-1525).

As only reported by *Matters*, MISO's tariff changes would prohibit a market participant from submitting or modifying Interchange Schedules during the operating hour, except as necessary for reliability purposes as determined by the Midwest ISO. MISO said that the changes are needed to prevent market participants from scheduling large quantities of intra-hour imports and exports during the fourth quarter of the hour, after they have seen the prices that will be included in the integrated hourly settlement price for that operating hour (Matters, 7/31/09).

While supporting MISO's correction of such "harmful" scheduling practices, AMP said that MISO's solution is too restrictive, noting that the scheduling flexibility available under the Midwest ISO tariff necessarily requires that the Midwest ISO ramp generation up or down in response to Interchange Schedules submitted by market participants. Market participants, in turn, alter their Interchange Schedules based on the Midwest ISO's ramp capability.

As such, AMP believes that Interchange Schedules submitted by market participants on the quarters of the hour should still be accommodated in cases when a multi-hour schedule has been denied due to system ramp limitations under the Midwest ISO's tariff. AMP said its "discrete" exception will preserve the flexibility that market participants require in order to respond to changing operational circumstances on the Midwest ISO system, without creating perverse pricing incentives.

IEU-Ohio Seeks Rehearing of PUCO Demand Response Limit on Reasonable Arrangements

Industrial Energy Users-Ohio applied for rehearing of a Public Utilities Commission Of Ohio rehearing order which held that customers with reasonable arrangements with either Columbus Southern Power or Ohio Power are prohibited from participating in PJM demand response programs until the Commission decides otherwise.

As only reported in *Matters*, PUCO, in a rehearing order on the AEP companies' electric security plan, denied the companies' request to bar all customers on the Standard Service Offer from participating in PJM demand response programs. PUCO deferred ruling on the request, stating it needed more information (Matters, 7/24/09).

However, in consideration of the need to balance the potential benefits to PJM load response participants and the costs to AEP-Ohio ratepayers, PUCO ruled that customers under reasonable arrangements with AEP-Ohio (including, but not limited to, Energy Efficiency/Economic Development Rider, economic development arrangements, unique arrangements, and other special tariff schedules that offer service discounts from the applicable tariff rates) are prohibited from also participating in PJM demand response programs, unless and until the Commission rules otherwise.

IEU-Ohio questioned how the Commission could make such a determination if it found that it needed more information to rule on AEP's request. The Commission's entry on rehearing fails to provide any meaningful explanation to demonstrate why or how the Commission came to its decision regarding reasonable arrangements, IEU-added, in contradiction of requirements in the Revised Code regarding findings of fact and supporting reasoning.

Furthermore, IEU-Ohio called the order unlawful as the specific prohibition for reasonable arrangement customers was not proposed by any party, and did not arise from any application for rehearing.

Industrials further said that if the Commission has concerns about the interaction of reasonable arrangements and PJM demand response programs, it should address such concerns on a case-by-case basis, since PUCO retains ongoing jurisdiction over all reasonable arrangements, permitting the Commission to change, alter, or modify a reasonable arrangement.

Briefly:

PPL EnergyPlus Wins CL&P LRS Load

Connecticut Light and Power reported that PPL EnergyPlus won 100% of its Last Resort Service load for the three-month period beginning October 1, 2009.

Staff Asks PUCT to Rule on Payment Database, Hard Disconnect Threshold Questions

PUCT Staff asked the Commission to consider at the August 26 open meeting three threshold questions posed by Staff regarding a customer bill payment database and hard disconnect policy before further proceeding with the project (36860, Matters, 7/28/09). The questions relate to (1) whether the Commission has authority to create a customer payment database, and whether it can compel REPs to report payment information to the database administrator; (2) whether the Commission has authority to mandate funding of the database; and (3) whether the Commission has authority to implement a hard disconnect policy.

PUCT Grants J.P. Morgan Option 2 REP Certificate

The PUCT granted J.P. Morgan Ventures Energy Corporation an Option 2 REP certificate (Matters, 7/14/09).

DaCott Management Receives Conn. License

DaCott Energy Management was granted a Connecticut electric aggregator certificate to serve commercial, industrial and municipal customers (Only in Matters, 5/6/09).

Draft Would Grant Verde Energy Conn. License

The Connecticut DPUC would grant Verde Energy USA an electric supplier license to serve residential, commercial and industrial customers under a draft decision (Matters, 6/17/09).

PUCO Approves Accelerated FirstEnergy Deferral Collections

The Public Utilities Commission of Ohio approved proposals from the FirstEnergy utilities to accelerate recovery of various deferred costs, including costs under the Rate Certainty Plan (Matters, 7/29/09). The FirstEnergy companies said accelerating deferral collections would save about $320 million in carrying costs. The accelerated collection will be accomplished through a distribution rider imposed only during winter months between September 2009 and May 2011, while still maintaining a differentiation in summer and winter bills. PUCO deferred ruling on changes to lengthen the period under which the FirstEnergy companies would purchase RECs from residential customers under a pending program, submitted as part of FirstEnergy's deferral filing, stating it would rule on the program in a related case.

Delaware PSC Issues Modified Draft of IRP Regulations

The Delaware PSC released revised proposed regulations to govern Delmarva Power's integrated resource planning process (Regulation Docket No. 60). The draft regulations are an outgrowth of stakeholder discussions and a prior proposal released in January 2009, but the Commission ordered that the revised draft shall be considered a new proposal subject to applicable notice requirements.

TCRF ... *from 1*

Reliant noted that variable price Electricity Facts Labels are required to reflect all recurring charges for the first billing cycle. REPs are also required to notify variable-priced customers on their bill how they can obtain the next month's rate.

"Therefore, it is not clear whether and how a REP can start passing through a TDU rate change at the same time and in the same manner that the TDU applies the new rate. Some amount of advance notice is required for the REP to implement any TDU rate changes," Reliant said.

The challenges posed by the disclosure rules become even more difficult as TDU charges change more frequently, Reliant added. "In addition to TCRF changes twice a year, there are transition charge updates, energy efficiency cost recovery ('EECRF') updates, and even new securitization charges for hurricane storm recovery. For example, Oncor may have eight or more TDU charge changes coming in the next 12 months. Those changes include the charges approved for the rate case, transition charge factor 1, transition charge factor 2, energy efficiency cost recovery factor, the September TCRF revision, the March TCRF revision, the rate case expense, and a possible revision to the advanced meter cost recovery factor," Reliant noted.

Reliant recommended that the Commission should ensure that REPs are able to pass through any TDU rate changes in the same manner and on the same timeline that the TDU applies the rate change, including, as necessary, providing REPs with adequate notice after a rate change is approved before it goes into effect. The frequency of TCRF updates should not be increased, Reliant added.

The TCRF rule holds that updates occur on March 1 and September 1 of each year. Reliant noted that while in practice TCRF filings are made 45 days in advance, the deadline is not required by rule. In addition, although the TCRF updates are generally approved administratively without changes to what is requested, that is not always the case. Reliant noted that the Oncor TCRF update that was approved in Docket No. 36599 for implementation on March 1, 2009 was different from the initial application filed on January 15, 2009. Moreover, Oncor didn't file a clean copy of the finally approved TCRF until March 2, 2009, Reliant said.

Furthermore, Reliant sought to apply its recommended notice provisions to TDU rate increases generally. "Once a TDU charge is approved through an order of the Commission, REPs should be given sufficient notice to comply with the requirements of the disclosure rule. This notice period should be 90 days, unless the Commission clarifies that the rule provisions in P.U.C. SUBST. R. 25.475 ... allow REPs to pass through the TDU rate changes as soon as they become effective," Reliant said.

Nodal ... *from 1*

under the not-to-exceed nodal budget of about $660 million.

The parking deck was one of the main issues which led to numerous non-signatory, non-opposing parties to a pending non-unanimous stipulation to set the revised ERCOT nodal fee, which was the subject of a hearing yesterday (Only in Matters, 8/5/09). Among other issues left to later litigation under the settlement is allocating costs of implementing parking deck NPRRs -- whether they should be treated as "nodal" expenses recovered through the nodal surcharge (currently assigned to generation QSEs) or "market" expenses recovered through the administrative fee allocated to load.

However, Smitherman, referencing pro forma budget numbers presented at ERCOT's Tuesday Board meeting, said he thinks that, "the reality is it's not how many options do we want to add off the parking deck, it's what can we afford."

Noting CapEx numbers of $60-70 million in the outer years of the pro forma 2011-15 data, Smitherman added, "We really got to start thinking about this project, not in terms of 'do I want the chrome wheels and the satellite radio,' [but instead] what can I afford on this vehicle?"

"If the parking deck is going to become bigger than the original nodal project, that's just unacceptable, at least to me," Smitherman added.

Dovetailing with the issue that once the nodal project goes live there will just be a single market (as opposed to zonal administration and nodal implementation currently), Smitherman said ERCOT needs to present its financial schedules to reflect the combined nodal and administrative fees, rather than addressing the fees as two distinct fees. That will allow the Commission to look at the fee and debt on an integrated basis.

Additionally, Smitherman and Commissioner Donna Nelson expressed concern about the use of a forecast showing increasing load in setting the amount of the nodal fee, while the administrative fee projections used at Tuesday's Board meeting used a flat load projection. ERCOT explained that the flat load projection used at the Board was part of its intent to seek approval of a method of recovering the administrative fee which is "de-linked" from load.

Still, it prompted questions from Commissioners regarding what would happen with the nodal budget and program if load growth does not meet ERCOT's projections. ERCOT said that the fee would remain at the proposed 37.5¢/MWh, but the collection period would be extended until the debt was paid off. The Commission directed ERCOT to produce schedules showing how it could service debt should load remain flat through 2014-15, and the nodal fee is set at 37.5¢.

Citing the lack of record evidence in the case, Nelson reiterated that the Commission has been put in an unfavorable position in ruling on the non-unanimous stipulation, especially considering there was so much discussion and criticism of the nodal budget as being unreasonable several months ago. But no party offered testimony drilling down into ERCOT's numbers.

The Commission's concern is heightened since the stipulation allows signatories to reserve the right to contest the reasonableness of nodal costs, which made Smitherman "uneasy." Smitherman suggested that if parties sign the settlement, it seems that they would agree that the nodal capital budget, pace of spend, 60/40 debt ratio, load growth assumptions, etc., are reasonable. In particular, Smitherman voiced concern that post go-live, parties will opportunistically raise protests to the reasonableness of nodal costs, particularly in the 2011 legislative session.

Smitherman also said that in the future, the Commission needs to have a discussion regarding the proper role of stakeholders and "ERCOT Inc." The Commission, Smitherman said, has to be able to rely on ERCOT as an unbiased market facilitator that doesn't have a revenue obligation. ERCOT has to have a point of view, Smitherman noted, and is uniquely positioned to be an unbiased arbiter, rather than ERCOT merely being the stakeholder community.