Energy Choice Matters

June 1, 2009

Texas Lawmakers Enroll Fixed Price Notification Bill

Entergy Competition Delay Heads to Governor

Texas HB 1822 has been enrolled after the House accepted Senate amendments to the bill, including requirements governing how and when REPs must send renewal notices for fixed price contracts. The bill heads to the governor.

The enrolled language for HB 1822 would require REPs to send residential customers a written notice of the upcoming expiration of a fixed-rate contract at least 30 days before the expiration date, but no more than 60 days before expiration, a timeline which differs from recently changed PUCT rules (see Matters, 5/29/09 for complete discussion).

Enrolled HB 1822 would also require all (not just residential) REP bills for fixed rate products to include the expiration date of the fixed rate product, as opposed to as estimated date or billing cycle of expiration.

HB 1822 would also require the use of common terms on REP bills, with such terms to be developed by the PUCT.

Entergy Transition to Competition

The Texas legislature also enrolled SB 1492, which would require the PUCT to cease work on Entergy Texas' transition to competition plan, and require Entergy to withdraw the plan (Matters, 4/29/09).

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TXU Opposes Several Discretionary Fees in TNMP Rate Case

TXU Energy opposed several fees charged by Texas New Mexico Power is a statement of position filed in TNMP's current rate case (36025).

TNMP is proposing to charge the greater of $200 or "as calculated" for tampering charges. TXU Energy said that it is not aware of a cost-based rationale for charging the minimum $200 fee, recommending that the minimum fee be removed and that TNMP recover its actual costs.

TXU opposed the minimum fee because it is not cost-based and because it will likely increase bad debt for REPs.

"TDSPs charge these tampering fees to REPs, but many times REPs are not able to collect the fees from customers. Savvy customers often switch REPs without paying the tampering fees which results in increased bad debt for the REPs. Imposing a minimum charge without merit will often incorrectly punish the REP, rather than the end-use customer who purportedly committed the tampering," TXU said.

TXU also objected to language in the current TNMP tariff which allows TNMP to collect a charge for locating its underground delivery facilities. TXU said that the Dig-Tess service provides free locates, and that TNMP appears to be using the facilities location charge in its tariff to charge REPs for locates requested by the REP's customers. TXU noted that the person or entity that is performing

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Cape Light Compact Sees Subsidization in Possible National Grid Solar REC Treatment

Customers on competitive supply should not subsidize basic service customers under National Grid's proposal to build 5 MW of utility-owned solar generation in Massachusetts, the Cape Light Compact said in comments emphasizing an inconsistency in Grid's testimony (09-38).

In one witness's testimony, Grid said that the cost and value of the RECs from the solar projects would accrue to all distribution customers. However, in other Grid testimony, a witness says Grid may, in the future, retain the RECs for basic service, and credit all distribution customers with the market value of the RECs (although Grid initially intends to sell the RECs into the market).

"If National Grid is allowed to keep the RECs for basic service customers only, then those customers on competitive supply would be subsidizing customers on basic service to some degree," Cape Light Compact said.

"More importantly, this may provide incorrect price signals in the marketplace to consumers and contribute to an unlevel playing field between competitive suppliers and National Grid," the Compact added.

AEP Companies Propose Simplification to REPs' Proposal to Adjust Estimates

AEP Texas Central and Texas North have recommended a simplified procedure to adjust estimated meter reads used for the purposes of a switch in the ERCOT market, under the proposed accelerated switching timeline (36536).

Under the modification, supported by CenterPoint Energy as well, adjustments to estimates would still occur in the two instances suggested by the retailers: either the losing REP's billed usage exceeds the total usage for that meter read cycle, or a customer disputes the estimate and the usage per-day under the estimate is found to be off by at least 25% (see Matters 5/29/09).

The AEP companies submitted clarifying language for the second situation in which an estimate may be modified. The AEP companies' language holds that, if the estimated reading for the switch resulted in the average kWh per day for the pre-switch period being 25% greater or less than the actual average kWh for the whole billing period in which the switch occurred, the TDU shall promptly adjust the estimated meter read based on the actual average kWh per day for the full billing month. TDUs would not have discretion to provide adjustments for estimates under the 25% threshold, as proposed by REPs.

Under AEP's plan, the TDUs would also not be compelled to share their methodology for making estimate adjustments as would be required under the previous REP revisions.

CPL Retail Energy, Direct Energy, Gexa Energy, Green Mountain Energy, Reliant Energy, First Choice Power, Stream Energy, TXU Energy and WTU Retail Energy also suggested new language holding that TDUs shall not charge a fee for the review or adjustment of an estimate as provided in the rule.

Oncor Confirms AMS Pre-pay Support

Oncor confirmed that, as scheduled, its Advanced Metering System (AMS) and interim work processes will have the capability to support prepay service (consistent with P.U.C. Subst. R. 25.498) starting today.

REPs must notify Oncor which of their customers with an AMS provisioned meter are prepaid, and Oncor will reconnect power to such customers after disconnect for non-payment within one hour of receiving the reconnect notice from the customer's REP.

The discretionary service charges for disconnect and reconnect of designated prepay customers with an AMS provisioned meter with remote disconnect/reconnect capability will be $0.

In the PUC's TDU Prepay Project Workshop in Docket No. 36233, it was agreed that a "Priority Code 5" in the 650_01 service request transaction would be used to identify Prepay Disconnects and Reconnects. Oncor said that it will be critical that REPs code the 650 service order requests with Priority Code 5 in order to complete the work request as well as to apply the $0 charge for the service orders. Oncor will not reverse service order charges if the service order requests do not contain the Priority Code 5.

For Disconnect for Non-Pay (DNP) TX SET 650 service orders with a Priority Code 5, Oncor will work the disconnect order in accordance with existing market rules, i.e. REPs must provide two business days notice prior to the requested completion date. Orders not received with at least two business days notice will be scheduled for two business days from date of receipt.

For pre-pay premises with an advanced meter, Oncor will disconnect service using its AMS system and will schedule disconnections in the early part of the day so that customers can have the opportunity to pay the REP and get reconnected the same day.

MISO Proposes to Restrict Credit Netting to Entities Providing MISO with Security Interest

The Midwest ISO submitted proposed tariff revisions at FERC to require that Market Participants grant a security interest to the Midwest ISO, in the amounts due to the Market Participant from MISO, as a condition for netting the Market Participant's obligations across all markets for the purpose of credit requirements.

Currently, the Midwest ISO nets within and across service categories any amounts owed to a Market Participant against the amounts owing from the Market Participant when calculating the Market Participant's Total Potential Exposure. Effectively, this reduces the amount of unsecured credit used by, or financial security required from, a Market Participant, thereby minimizing barriers to entry.

However, MISO said that revisions are needed because of a concern involving the application of bankruptcy and creditor's rights law in the event of a Market Participant's insolvency. There is a concern that the Midwest ISO's current netting procedures may not be permitted under applicable bankruptcy and creditor's rights laws.

Under the proposed changes, netting both within and across service categories would continue for Market Participants if they grant the Midwest ISO a first priority security interest in the account receivables due from the Midwest ISO. Qualifying municipalities and joint action agencies, however, would be exempt from the requirement since they are unable to provide a first priority security interest due to the nature of their financings.

Market Participants that elect not to grant the security interest will no longer have their charges and credits netted across all service categories when calculating their Total Potential Exposure. Instead, they will only be permitted to net within certain subgroup service categories: energy transactions; virtual transactions; FTR transactions; transmission service; and Module E transactions.

FERC rejected a security interest requirement in 2004, but MISO said conditions have changed, and added that its new proposal has addressed the Commission's concerns.

The Commission's 2004 order rejecting the Midwest ISO's request found that the provisions imposed an unfair burden on Market Participants who may be unable to grant the security interest, and as a consequence, would have their credit severely limited. MISO said that the exemption for munis eases that concern.

"For all other Market Participants, the grant of the proposed security interest will not unduly burden Market Participants. It is important to note that the receivables being secured are amounts already owed to the Market Participant by the Midwest ISO. Given the uncertainties of the law of setoff, it is unlikely any other creditor is relying on these amounts," MISO said.

PUCT, ERCOT Staffs Ask for Specifics on Changes to Congestion Zone Process

PUCT and ERCOT Staffs have separately asked the Commission to provide greater guidance on reforms needed for the ERCOT congestion zone designation process, which grew out of AEP Energy Partners' appeal of the 2009 congestion zones (36416).

ERCOT Staff asked that the Commission specifically identify the issues or Protocol provisions that the Commission believes should be subject to Protocol Revision Requests. While the Commission's general concerns were discernible from the May 21 Open Meeting discussion, ERCOT Staff said it would appreciate any further guidance the Commission could provide to direct the work to be undertaken by ERCOT Staff and the Technical Advisory Committee.

PUCT Staff likewise asked for direction from the Commission, proposing that ERCOT add more specificity to the relevant protocols, including Protocols 7.2.1 and 7.2.2, as to the types of statistical clustering analyses that ERCOT Staff may utilize to determine congestion zones. ERCOT should also be directed to add more specificity as to the circumstances under which ERCOT Staff may use a particular type of statistical clustering analysis, and to specify the types of operational concerns that ERCOT Staff may take into consideration in developing congestion zones, PUCT Staff suggested.

Briefly:

Northeast Energy Partners Seeks Md. Broker License

Northeast Energy Partners applied for an electric broker license at the Maryland PSC, to serve commercial and industrial customers at the four investor-owned utilities.

PUCT Staff to Post Proposed Nodal Performance Metrics

The Staffs of the PUCT, ERCOT, Texas Regional Entity (TRE), and the Independent Market Monitor (IMM) have jointly developed a list of proposed performance metrics with pass/fail criteria for ERCOT, Qualified Serving Entities (QSEs), and Transmission Service Providers (TSPs), for certain functions critical to the reliability of the electric grid in the nodal market structure, the PUCT Staff said in announcing a June 12 workshop on the metrics. The initial list of performance measures and criteria will be filed in PUCT Project No. 37052 on June 3, Staff said. The Staffs emphasized that stakeholder input at the workshop will be critical as they intend to seek urgent status or other expedited process for the metrics.

The Utilities Group Awarded Ohio Broker License

The Utilities Group was granted an electric broker-aggregation certificate by the Public Utilities Commission of Ohio. The Utilities Group said it will mostly focus on non-residential customers in Duke Energy's territory in Southwest Ohio (Matters, 4/28/09).

Priority Power Earnings Down from Lower Demand

Broker Priority Power reported lower first quarter earnings of $61,000 for the first quarter of 2009, a decrease of almost 92% versus the same quarter in 2008. Recurring revenue was down 12% versus last year due to reduced aggregation fees stemming from lower energy demand caused by economic factors, particularly among Priority's oil and gas customers. The year-ago quarterly revenues also included a one-time payment of $300,000 related to a power plant development project. General and administrative expenses were 43% higher than the same quarter in 2008 due to increases in sales staff. Priority said a number of underperforming sales staff have been released recently, and management expects G&A expenses to decrease in future quarters.

FERC Denies FirstEnergy Solutions' Request to Convert to Network Service

FERC denied a request for declaratory order from FirstEnergy Solutions which sought to convert 1,000 MW of firm point-to-point service reservations to comparable network integration transmission service in PJM (EL09-39). FERC held that there is no right to convert point-to-point service to network service under PJM's OATT. FirstEnergy Solutions must request network service on the same terms and conditions as other customers under the PJM OATT, FERC said.

ERCOT Says Reserve Margin Adequate Through 2014

ERCOT said that reserve margins are expected to be ample through 2014, with a 16.8% margin for this summer and a 13.9% margin in 2014. The minimum required reserve margin is 12.5%. ERCOT reported a net increase of 1,140 MW in installed capacity since its December 2008 assessment. ERCOT also reported that potential resources in the final phase of the interconnection process but lacking either an air permit or interconnection agreement (and therefore not counted in the reserve calculation) range from 7,858 MW in 2010 to 25,463 MW in 2014. The 2009 summer peak is forecast at 63,491 MW, some 1,731 MW lower than the last forecast in December 2008, reflecting the current slowdown in economic conditions. However, the forecasts anticipate a recovery in the economy over the next five years with an increase in the average annual growth rate from 1% in the near term to as high as 3% in 2012 and 2013. Available resources for the 2009 summer peak total 72,712 MW.

PPL Unit Selling Long Island Generation Business to J-POWER

PPL's generation subsidiary has agreed to sell its Long Island generation business to J-POWER USA Development Co., Ltd. for approximately $135 million plus working capital. The business consists of PPL Edgewood Energy, LLC, which owns a 79.9-MW natural gas-fired electric generation facility in Brentwood, N.Y., and PPL Shoreham Energy, LLC, which owns a 79.9-MW oil-fired electric generation facility in Brookhaven, N.Y. The output of both facilities is fully contracted to the Long Island Power Authority. While the units are "good assets," PPL said they are not core to its concentrated generation positions in the PJM market and the Northwest.

FERC Approves NYISO Penalty Pass-Through Mechanism

FERC approved, unmodified, tariff provisions from the New York ISO to allow it to pass through penalty costs from reliability violations to market participants (Matters, 4/3/09). The tariff will allow NYISO to recover such costs by application to FERC on a case-by-case basis. Recovery could either be allocated directly to the entity causing the violation, or in cases where such assignment is not possible or the ISO is itself responsible, recovery could be assigned to all customers and market participants, with 50% allocated to energy injections, and 50% allocated to withdrawals. FERC dismissed concerns raised by the New York PSC about costs being passed onto retail customers, stating that its action does not grant LSEs the authority to automatically pass through such penalty costs to end users, and that the PSC may address such concerns in any future section 205 filings where such a cost allocation is proposed.

Md. IOUs Report Adequate Summer Supplies

Allegheny Power, Baltimore Gas and Electric, Delmarva Power and Pepco reported adequate summer 2009 electric supplies in updates to the Maryland PSC. Previous projections of shortfalls have prompted the PSC to consider, and implement, various non-market interventions to ensure adequate supplies. BGE also took the opportunity to reiterate that achieving its aggressive target of demand resources in future years will depend on Commission approval of its Smart Energy Pricing tariffs, which can be realized only with advanced metering technology.

Entergy ... *from 1*

Under the bill, any party could petition the Commission to initiate a proceeding to certify a qualified power region for the Entergy area when the conditions supporting such a proceeding exist. If the Commission certifies a qualified power region for Entergy, the Commission could not approve a transition to competition plan until at least four years after certifying the qualified power region.

The bill also calls for a competitive generation tariff at Entergy.

TNMP ... *from 1*

an excavation must make the request for facilities location, not the REP, and argued that it is unreasonable to charge a REP for such a service. TXU Energy recommended that the location service costs should be embedded in the TNMP rates and not separately charged to REPs.

TNMP should also adjust its use of demand ratchets, TXU said. TNMP currently applies a demand ratchet on commercial customers with a load higher than 5 kW, but TXU recommended that TNMP should follow Oncor's example in waiving demand ratchets for all commercial loads with a maximum annual demand of 20 kW or less.

TXU also believes that billing commercial customers on a kWh consumption basis at some level above 20 kW should be studied to see if it would be a net benefit to the market, suggesting 50 kW may be an appropriate cutoff.