Energy Choice Matters

March 6, 2009

Reliant Favors End of Rescission Period; REPs Oppose Meter Read Estimates for Switches

The PUCT should eliminate the three-day rescission period in the Substantive Rules because it is no longer workable under an accelerated switch timeline, Reliant Energy said in comments on a Staff proposal to process switches faster (36536).

Under Staff's proposal which would complete switches within seven days via an expedited meter read (Matters, 1/27/09), the rescission period would remain, but REPs could execute a switch before the period expired. However, Reliant noted REPs not waiting for the period to expire would assume the full risk of power supplied during that period, should the customer ultimately decide to cancel. "This is precisely the reason that the right of rescission is not applicable to a move-in -- market processing timelines, designed to provide the customer with prompt service, render the rescission period impractical," Reliant said.

Retaining the rescission period would extend the switching process to about two weeks, Reliant said, since REPs seeking to avoid risk would delay submitting a switch to ERCOT. REPs would wait three federal business days for the customer to receive the terms of service via mail, and then another three days for the rescission period to expire before submitting the switch, thus frustrating the accelerated process.

Reliant noted federal law would still mandate a rescission period for residential door-to-door sales, but saw no need for other contracting methods to offer the cancellation period. For door-to-door sales, since the terms of service would be given to the customer at the point of sale,

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Detroit Ed Plans to Mitigate Renewable Charge on C&Is to Prevent "Unfair Competitive Advantage"

Detroit Edison filed its renewable energy plan with the Michigan PSC, proposing to mitigate customer surcharges for low-usage secondary and primary commercial customers to, "mitigate unfair competitive advantage," accruing to competitive suppliers from the surcharges required for compliance with new renewable standards.

Detroit Edison's program would build or procure 1,200 MW of renewable generation, with an annual revenue requirement of $111 million. Detroit Edison would recover such costs through a monthly surcharge on bundled service customers over 20 years, at a maximum of $3/meter for residential customers, $16.58/meter for secondary commercial customers, $187.50/meter for primary commercial and industrial customers.

However, Detroit Edison applied to impose lower than maximum surcharges on lower-usage C&I customers, because it said imposing the maximum on low usage customers would result in large bill increases, which may drive customers to competitive supply. Such a customer decision to shop would not be because the competitive supplier could provide less expensive electric generation service, "but merely because of a rate anomaly," Detroit Edison claimed. Because competitive suppliers can implement revenue recovery surcharges for their own renewable plans without the same Commission oversight Detroit Edison faces, competitive suppliers could provide

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ConEd Files to Build Utility-Owned Solar

Consolidated Edison filed with the New York PSC to build 1.8 MW of utility-owned solar, and to receive the benefits from 5 MW of customer-owned solar and 5 MW of merchant developed solar, under its Solar Energy Pilot Program.

ConEd will pursue various funding sources for the projects, including federal incentives, Regional Greenhouse Gas Initiative payments, and NYSERDA funds. To the extent those funds do not cover the $20-25 million pricetag, ConEd applied to use funds from the New York RPS program. However, should the PSC rule RPS funds are not appropriate for the projects, ConEd said costs would be recovered under the current MSC/MAC mechanism, in the same way that it recovers costs for its retained generation. ConEd compared the solar program to its demand side management programs, which are recovered from all delivery customers.

Aside from the 1.8 MW of utility-owned solar, ConEd would conduct an RFP for 5 MW of solar facilities to be located in its service territory. The RFP will focus on larger solar installations (200 kW or larger), and will obligate the vendor to provide RPS attributes to ConEd at a fixed price over the term of the contract.

ConEd would also develop 5 MW of customer-owned and sited distributed solar. Under the program, customers would assign value of RPS attributes and, if applicable, the right to wholesale capacity market payments to ConEd for a period of up to 15 years to offset the costs of the initiatives.

ConEd said the goals for the program are to understand the network impact of solar resources, to test market mechanisms, and to engage customers and stakeholders.

D.C. PSC Says WGL Should Hedge to Avoid Price Spikes, But Reap Price Falls

Washington Gas Light should consider hedging alternatives and not focus its hedging program solely on minimizing price variability, "because minimizing price variability limits WGL's ability to take advantage of any downward price movements," the District of Columbia PSC ordered in accepting a report on WGL's pilot hedging program.

"[C]ustomers should be able to benefit from any decrease in gas prices as well as be protected from price spikes," the PSC said. "[V]olatility associated with declining gas costs is not detrimental to ratepayers," the Commission added.

Thus the PSC directed WGL to continue to study minimum load requirements, the possibility of purchasing hedging volumes year round, the possibility of longer-term commitments, and other pricing tools that would enhance the hedging program. The Commission directed WGL to report on whether it should limit its hedging purchases to the months of May through August, or extend hedging into September and October.

Still, the Commission did disagree with the Office of People's Counsel, which had argued that WGL's hedging program should be more flexible and less mechanical when prices are falling, as the PSC said such actions may be considered speculative in nature. "Such actions, for example, could suggest that WGL is attempting to 'time the market', which is speculative in and of itself," the PSC said.

While achieving its goal of reducing volatility, WGL's 2007-2008 hedging pilot program incurred $1 million in additional costs for District of Columbia customers, with residential bills estimated to be $8 higher in the winter and $9 higher annually due to the program.

Md. PSC Staff Says Gas Supplier Renewals Should be Investigated

Maryland PSC Staff suggested investigating competitive gas supplier contracting to confirm that appropriate and timely contract renewal notices were provided to customers per COMAR 20.53, Staff said in a presentation on a high number of customer complaints regarding winter electric and gas bills (Case 9175).

The case, thus far, has been focused mainly on utilities that have received a deluge of complaints relating to higher bills. While the PSC told lawmakers there was no "smoking gun" or single cause for the high bills, several factors include a longer meter reading period in December and January, colder weather in December and January as well as a milder November, and increased commodity rates, though the increases are much smaller than previous increases and do not explain the entirety of the high bills.

The Commission's Office of External Relations surveyed the bills of 15 complaining customers to look for common trends. The Office reported that five customers had gas supplier contracts that reset to higher rates. In one example, a customer's supplier contract increased the rate from $1.189/therm to $1.599/therm, while Baltimore Gas and Electric's standard rate ranged from $1.0155/ therm to $0.9309/therm.

The Commission also told legislators that customer confidence and trust are very low, and that customers do not believe that utilities are investigating their complaints. Customers are skeptical of utility explanations and believe that "something is going on," the PSC said.

Complaints are expected to escalate as winter protections for service disconnections rolloff, since utilities are building record levels of arrears.

Briefly:

PUCT Staff Revises POLR Draft Rule

PUCT Staff revised its latest POLR proposal to include Commissioner comments from the February 26 open meeting. Among the changes are that voluntary POLRs will be required to submit a competitive market rate to ERCOT on a monthly basis that would be used in any mass transition, rather than providing the rate at the start of a mass transition, in order to speed the process (Matters, 2/27/09). The changes also clarify how ERCOT is to identify customers involved in a mass transition. Under the proposal, ERCOT would implement system changes and create a new transaction if necessary that will identify mass transitioned customers for a period of 30 business days. This new identification and associated changes shall communicate to the market that the customer was acquired in a mass transition, to ensure that the customer is not charged an out-of-cycle meter read. To the extent possible, Staff said the system changes should be designed to ensure that for a period of time following a mass transition, when a customer switches away from a POLR, the switch transaction is processed as an unprotected, out-of-cycle switch, regardless of how the switch was actually submitted. The identification would terminate at the first completed switch or at the end of the 30-day period, whichever is first. Staff did not modify language regarding the mandatory POLR category, deposit requirements, or pricing for voluntary and mandatory POLRs, as there will be continued discussion on those matters.

PUC Staff Recommend LIDA Discount of 15.5%

PUCT Staff recommended that the low-income discount percentage for the summer of 2009 should be set at 15.5% of the POLR rates for each service territory, based on appropriations and expected enrollment (28073). At the current average POLR rate of $0.191/kWh, the discount would equal $0.0296/kWh. The discount is to be provided by REPs to eligible customers May through September.

BlueStar Signs Credit Facility to Support Growth

BlueStar Energy Services said it has closed a new credit facility to fund its continued growth. The new financing consists of a senior secured revolving line provided by RBS Citizens, NA and a subordinated mezzanine loan provided by RBC Capital Partners.

DBS Energy Certified as Efficiency Partner

The Connecticut DPUC granted energy management consultant DBS Energy certification as a General Partner under the Connecticut Electric Efficiency Partner Program (Matters, 10/20/08). The program funds incentives for installation of gas-driven chillers and ice-based thermal storage. The DPUC did not designate DBS as a vendor partner in the program, as the Department envisions vendor partners will be companies offering only their own proprietary equipment, while DBS will be installing third-party devices. DBS also holds an electric supply license in Connecticut (Matters, 7/31/08), and intends to offer ice storage solutions.

Hudson Energy JV Granted REP Certificate

Hudson Energy JV, a subsidiary of current certificate holder Hudson Energy Services, was granted a REP certificate by the PUCT (Matters, 2/20/09).

Michigan PSC Approves Sale of MichCon Native Base Gas

The Michigan PSC approved a settlement under which MichCon and ratepayers will share the proceeds from the sale of 4 Bcf of native base gas on a 50-50 basis (Matters, 10/3/08). The excess gas is available due to storage improvements. The sale is expected to produce benefits of $12 million for customers.

Switching *... from 1:*

switches would still be accelerated, as REPs would not have to wait the three federal business days for the customer to receive the terms of service before calculating the start of the rescission period.

Supporting Staff's proposal to eliminate the ERCOT postcard, Reliant noted that customer complaints related to slamming of electric service have dropped 72% since their peak in 2003.

Consumer groups, however, argued that the postcard process remains necessary to protect customers, and proposed an alternative that would allow the process to continue while not delaying the proposed six-day switching timeline.

Under a proposal from the Texas Ratepayers' Organization to Save Energy and Texas Legal Services Center, the postcard would be maintained, but would only inform customers of their switch, and would direct customers to call the new REP if the customer did not authorize the switch. The postcard would no longer provide an ERCOT number customers could call to cancel the switch, though ROSE and TLSC recommended that within 12 months, the interactive telephone system be modified to provide a toll free number customers could call that would automatically notify the REP or REPs of the customer's contact.

The modified postcard would allow customers to be informed of potential slamming before receiving their first bill from the new REP, ROSE and TLSC noted. However, the process will depend on the new REP submitting the necessary Texas SET transaction to ERCOT to return a slammed customer, compared to today's automatic process.

Thus, ROSE and TLSC said rules should be established to assure that REPs act quickly on a customer's call regarding slamming. A REP's customer service line should have a separate call category for slamming (e.g., if you have received notice from ERCOT and would like to cancel a switch, please press 4), and the phone should be answered by a representative that is fully informed about how to cancel a switch, TLSC and ROSE said.

TLSC and ROSE further recommended that the REP should be required to notify ERCOT within two business hours of being contacted by a customer cancelling a slam, similar to standards adopted in regard to REPs posting payments on disconnected customers' accounts. "By having a time for action standard in place REPs will give priority to the cancellation and the customer's expectation for action is well defined," ROSE and TLSC said. The Steering Committee of Cities Served by Oncor added that the correction of all unauthorized switches should take priority over any other switches.

TXU Energy also favored keeping the postcard as a notification tool, but removing the ERCOT cancellation number and instructing the customer to call the new REP.

The Cities also suggested that if the ERCOT postcard is eliminated, REPs should be required to use independent third party verification of the customer's switch. Currently, verification of only door-to-door and telephonic switches must be recorded, with no third-party requirement. The Cities also suggested that TPVs be used for switches made over the internet or by mail.

Furthermore, the Cities argued that a REP which obtains a new customer via an unauthorized switch should be required to repay 150% of any charges which were collected as a result of the unauthorized switch, with 100% retained by the valid REP and the remaining 50% given to the customer for his/her time and trouble, similar to requirements imposed by the FCC on long distance providers. "In order to discourage slamming, if the Commission finds that a customer was switched without his/her consent, the REP which sent the bill to the customer should be required to pay the customer 50% of the bill amount, even if the customer did not remit any payment for the bill," Cities added.

Estimated Reads

REPs opposed the proposed rules which would allow TDUs to estimate the expedited meter reads used for the switch, stating it would frustrate customers while harming REPs.

Estimated reads should not be routine, Reliant said, since estimated reads for the purpose of a switch will necessarily assign consumption incorrectly among providers. The Alliance for Retail Markets agreed, warning that estimated reads are a recipe for a "customer relations nightmare." Over-estimates could produce a spike in the customer's first bill with their new REPs, creating ill-will towards the REP if the customer expected savings. Under-estimates may lower the amount in the first bill with the new REP, which may produce sticker shock in later bills, again creating customer frustration.

Moreover, estimated reads may create a windfall for the new REP to the detriment of the former REP in cases where usage is not properly assigned, and the new REP ends up billing and collecting for power actually delivered by the old REP, ARM noted. The old REP would be harmed in such instances, by not fully recovering the cost of power sold to the customer.

ARM noted that the proposed language contains no restrictions on a TDU's use of estimated expedited meter reads, meaning, in theory, the TDU could estimate every expedited meter read. In contrast, the current switching protocols only allow use of an estimate for a switch in cases where the TDU has made every reasonable effort to obtain actual meter read data and "absolutely cannot" obtain it.

However, Oncor defended the need for estimates to meet the accelerated timelines in the proposal. Without estimation, the cost to the market of the new process will substantially increase from hiring new staff, Oncor said. If estimations are not allowed, the additional costs will be approximately $5.1 million, excluding programming changes, Oncor calculated. Within Oncor's service area, the expedited switches that would be candidates for estimation will be less than 60% of the total expedited switches at the time the rule is implemented, and less than 40% of the total expedited switches one year later, Oncor reported.

Disconnections and Bad Debt

TXU Energy cautioned that the expedited switch process could encourage customers to switch providers in order to avoid making payment. Since switches would only take six calendar days, customers receiving a disconnect notice, which gives the customer 10 days to cure the problem before cutoff, would have ample time to switch to a new REP to avoid disconnection. Such switching will result in more defaults and bad debt due to the timing related to disconnects for non-payment, TXU noted. "The increased capability of customers to switch prior to disconnection for nonpayment may cause a significant financial impact to REPs, particularly if they do not have a sufficient deposit to cover outstanding billings, and especially if they were at the beginning or somewhere within the timeframe of a deferral from a previous period," TXU said.

Number of Switch Types

As exclusively reported by Matters (Matters, 2/19/09), ERCOT asked for clarification if the new expedited switch process is meant to replace on-cycle switches, or is meant as a new transaction in addition to an on-cycle switch. ERCOT reported that keeping the current on-cycle and off-cycle switches, while adding a third category of expedited switches, would require significant system changes to its stacking logic, taking approximately 12-14 months to complete and costing $4-5 million. Conversely, using expedited switches in place of the on-cycle process would only require minor system changes and no Texas SET version changes.

ERCOT also recommended that the proposed timeline for expedited switches be changed from six calendar days to four business days, as most market logic is based on business days, in a recommendation echoed by many stakeholders.

Move-In Transactions

The Joint TDUs argued that the rule should make clear that a REP must not use a move-in request instead of a switch request when the customer is switching REPs and no move-in has occurred. Similarly, a switch request must not be used when there has been a move-in by a new customer, TDUs said, as the free expedited switch should not be used to avoid paying the charge that will continue to apply to a move-in.

***Detroit Ed** ... from 1:*

significant savings to these low usage customers by charging their higher usage customers more, Edison said.

To prevent "shifting the competitive landscape," Detroit Edison proposed to mitigate the surcharge imposed on lower-usage C&I customers.

For secondary commercial customers, Detroit Edison proposed limiting the surcharge to $4/month for customers using 0-400 kWh, $8 for customers using 201-850 kWh, and $12 for customers using 851-1,650 kWh. Customers above that threshold would pay the full $16.58 surcharge.

For primary C&I customers, the proposed mitigation is $16.58/month for customers using 0–11,500 kWh and $140 for customers using 11,501–41,500 kWh. Customers above that level would pay he maximum $187.50/ month.

As permitted under Public Act 295, Detroit Edison proposed owning 50% of the renewable capacity to be built to meet the Act's requirements. Detroit Edison would own 565 MW of wind by 2029, plus 15 MW of solar, with another 29 MW from co-fired renewable fuels at its existing plants.

Detroit Edison said that, on average, utility-owned projects will be more cost effective and beneficial to customers than projects contracted for under long-term renewable energy contracts. "Given current and anticipated capital market conditions, the average independent renewable energy developer will likely utilize more debt and have higher return requirements than Detroit Edison," the utility argued. Detroit Edison also claimed that it will likely incur additional costs from competitive PPAs due to debt that is imputed by credit rating agencies for the renewable energy contracts it signs with merchant developers.

Detroit Edison also filed nonbypassable surcharges to implement efficiency programs under its energy optimization plan. Customers implementing self-directed energy efficiency programs could bypass most of the surcharges, except the portion dedicated to low-income programs. A list of the surcharges per rate class can be found in case U-15806-EO.