Energy Choice Matters

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BGE Proposes TOU Rates as Default Service for Residential Customers in Smart Meter Application

Baltimore Gas and Electric has petitioned the Maryland PSC to make a two-tier time-of-use rate with a peak-time rebate the default generation service for residential customers starting in 2012, as part of its plan to install 1.36 million advanced electric meters throughout its service territory.

Under BGE's proposal, residential customers would be served on time-of-use rates for the summer period (June 1 through September 30), and a single flat rate for the remaining months. The summer time-of-use schedule would consist of peak hours (2 p.m. to 7 p.m. on non-holiday weekdays) and non-peak hours. During the summer peak hours, customers would also be eligible to receive a rebate for reducing electric usage during critical days as declared by BGE. Assuming normal summer weather, BGE expects to declare 12 critical days (which equates to 60 hours) each summer.

The peak-time rebates would be competitively neutral and available to customers served on competitive supply, except in cases where such shopping customers were already in a similar load reduction program with their alternative supplier. The rebate would be a distribution credit on bills and would not affect generation rates.

The residential time-of-use rate design would combine all of the existing residential rate schedules (R, ES, RL1, and RL2) into one standard rate schedule.

Pending the outcome of a pilot this summer, BGE expects to propose a time-of-use mechanism with peak time rebates as the default rate for small commercial customers (rate schedules G and GS) as well.

Time-of-use rates are "appropriate, even compulsory" to utilize the capabilities of advanced meters and to further drive down energy and capacity prices in the region, BGE said. By offering

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Conn. OCC Says 20% Limit on Bilateral Contracts Should Remain for Now

The percentage of Standard Service load served by bilateral contracts should not exceed the current 20% cap, the Connecticut Office of Consumer Counsel said in comments on a draft procedural order that would govern the process of procuring such long-term contracts.

As only in reported in *Matters*, Connecticut Light and Power has asked the Department to lift the 20% cap imposed by the DPUC last year in an order allowing the utilities to procure a portion of Standard Service through long-term contracts and bilateral negotiations (Matters, 7/8/09).

OCC, however, said that any expansion of the load procured bilaterally would be premature, given that the program is in its "early stages." More experience is needed with bilateral contracting before lifting the 20% cap, OCC said. The Retail Energy Supply Association also urged the Department to maintain the 20% cap. Developer Ansonia Generation, however, saw no reason not to lift the 20% cap.

RESA further noted that in the Department's 2008 decision allowing bilateral contracts, the DPUC held that, "For bilateral contracts to provide meaningful benefits they must break the link between natural gas prices and electric rates."

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TNMP Rate Case Stipulation Prices Tampering Charges at "As Calculated" Value

A unanimous stipulation in Texas-New Mexico Power's rate case would remove TNMP's original proposal to charge the greater of $200 or "as calculated" for tampering charges. Instead, TNMP's discretionary tampering charges shall be limited to an "as calculated" value in the tariff filed to comply with the rates approved based on the stipulation.

TXU Energy had opposed TNMP's proposal to charge the higher-of $200 or the "as calculated" value, due to a lack of cost justification. TXU also said that the proposal would have likely increased bad debt for REPs (Only in Matters, 6/1/09).

The stipulation would also eliminate the demand ratchet for customers whose peak demand is equal to or less than 20 kW and for municipal pumping customers.

Among other parties, the unanimous stipulation was signed by TNMP, PUCT Staff, TXU, Reliant Energy, and the Office of Public Utility Counsel.

FirstEnergy Utilities Seek Rehearing of NOPEC Waiver, Cite Discriminatory Impact

Ohio Edison and Cleveland Electric Illuminating sought expedited rehearing of the Public Utilities Commission of Ohio's decision ordering the FirstEnergy utilities to stay the imposition of any switching fees on the Northeast Ohio Public Energy Council's electricity supplier during the pendency of NOPEC's complaint regarding the switching fees.

As only reported in *Matters*, PUCO found NOPEC was likely to succeed in its complaint that the $5 per customer switching fee is prohibited by administrative rules which bar the imposition of fees on customers in a governmental aggregation (Matters, 7/9/09).

Aside from reiterating earlier arguments that the prohibition does not preclude charging fees to suppliers of governmental aggregations, the FirstEnergy companies said that the order, "has placed the Companies in the untenable position of exempting only one specified governmental aggregation supplier, to the apparent exclusion of all other governmental aggregation suppliers," potentially running afoul of state policy as set forth in R.C. 4928.02 and non-discrimination provisions of Ohio law.

The stay, the utilities argued, will cause them to, "discriminate in favor of Gexa [NOPEC's supplier] and against other governmental aggregation suppliers."

"NOPEC essentially has convinced the Commission to tilt an otherwise level playing field in favor of Gexa, thereby giving it a competitive advantage over other governmental aggregation suppliers," the FirstEnergy companies said.

If the Commission does not lift the stay, the utilities asked that the switching fee be waived for all other governmental aggregation suppliers.

The FirstEnergy companies promised that if the fee is charged and later held to be in violation of the Ohio code, the utilities will refund the fee, even though the Commission has recognized that it may not have authority to order a refund once the fees have been collected due to the prohibition on retroactive ratemaking.

CAISO Protests PG&E Interconnection Security Waiver as Discriminatory

The California ISO protested a request at FERC from Pacific Gas and Electric to waive the interconnection security requirement for a utility-owned generation project, since the ISO believes such a waiver would give PG&E an undue competitive advantage (ER09-1336).

PG&E has requested that FERC accept a non-conforming pro-forma Large Generator Interconnection Agreement (LGIA) for the interconnection of PG&E's Humboldt Bay Re-Powering Project to the ISO. In its request, PG&E is seeking to grant itself a waiver from the security requirements of Section 11.5 of the pro forma interconnection agreement that requires PG&E in its role as the Interconnection Customer to provide security to PG&E as the Participating Transmission Owner.

"The ISO is informed and believes that PG&E has applied LGIA Section 11.5 to all other non-utility generating projects interconnecting to

PG&E's transmission system. If granted, PG&E's proposal would result in granting undue preferential treatment to PG&E as an Interconnection Customer by virtue of PG&E's status as the Participating Transmission Owner. A non-utility owned generation project would not receive the same consideration from PG&E," CAISO said.

"If, as asserted by PG&E, funding and security requirements do not apply to PG&E as an Interconnection Customer for its utility owned generation project, then all else being equal that generation project will have a competitive advantage over other non-utility owned generation projects that participate in PG&E procurement solicitations," CAISO noted.

Peoples, North Shore Oppose Moving Choice Administrative Charges into Base Rates

Peoples Gas and North Shore Gas opposed several requests made by retail suppliers regarding the LDCs' transportation and choice programs, including moving administrative and consolidating billing charges into base rates, and shortening the enrollment timeline.

In direct testimony in the LDCs' rate cases, several retail suppliers sought to move the Choices For You (CFY) Administrative Charge and LDC Billing Option charge into base rates, similar to treatment at Nicor.

However, in rebuttal testimony, Peoples and North Shore countered that the costs recovered under the Administrative and LDC Billing Option charges arise from costs that are caused by the choice programs. "Including such costs in base rates would result in sales customers paying for costs caused by transportation customers," the LDCs said, noting costs applicable only to sales service are bypassable by choice customers, so costs only related to choice service should not be imposed on sales customers.

Peoples and North Shore also opposed suppliers' request to shorten the enrollment window which was recently expanded to 19 days. The LDCs said that due to Senate Bill 171, they expanded the window from eight days to 19 days to ensure that service was not switched to a competitive supplier until 10 business days after the date on the utility's notice to the customer. The LDCs cited an example of a supplier enrollment submitted on November 25, 2009 as requiring 19 calendar days before the switch can legally occur, due to holidays and weekends pushing out the date by which the utility sends the enrollment notice, and then the days included in the 10 business-day rescission period.

Likewise, the LDCs said that SB 171 does not allow new delivery service customers to take service from a competitive supplier immediately upon initiation of service. The utilities also cited operational problems in enrolling new delivery service customers with an alternative supplier.

The utilities opposed suppliers' proposal to automate the transfer of credit balances from migrated sales customer accounts directly to the new competitive supplier. "The Utilities have serious concerns about possible disputes with customers over whether the supplier has a right to receive credit balances without explicit approval," the LDCs said.

In response to supplier comments, Peoples and North Shore have proposed to cease rounding to the nearest dekatherm in the Maximum Daily Quantity calculation. The Maximum Daily Quantity will instead be rounded to the nearest therm.

The utilities do not agree to implement super pooling for purposes of determining Critical Day imbalance charges because the LDCs argued that suppliers have a range of tools that, if used properly, can greatly minimize, if not avoid, imbalance charges, and because the proposal burdens the utilities with costly and complex system and process changes for events that are likely to occur only a few times a year.

The LDCs opposed suggestions that they offer all four NAESB intra-day nomination cycles, but are willing to offer an additional late nomination cycle similar to the mechanism recently approved at Nicor.

Peoples and North Shore said that allowing suppliers to use all four NAESB intra-day nomination cycles would cause them to be so busy reacting to all of the transportation customers' intra-day nominations and balancing and rebalancing the system, that decisions regarding sales customer purchases, injections, withdrawals, etc. could be suboptimal, leaving the system out of balance with the pipelines, and incurring imbalance charges or experiencing a system failure.

Instead, the LDCs offered to add a late nomination for a trial period of four years. Under this option, the customer or its supplier must make the nomination to the utilities no later than 3:00 p.m. central time (Evening Cycle Nomination) on the business day prior to the Gas Day on which the Evening Cycle Nomination is to be effective. On critical supply surplus days, no increases will be allowed. On critical supply shortage days, no decreases will be allowed.

The utilities opposed an Illinois Commerce Commission Staff proposal that would allow large volume transportation customers to purchase Allowable Bank without also purchasing standby service, arguing that it would require allocating unrealistic levels of storage to the unbundled Allowable Bank, and would also raise operational issues.

Peoples and North Shore agreed to develop a storage carrying cost credit for the large volume transportation programs, Riders FST and SST, similar to the credit in place for small volume customers. The credit would be applied to customer bills as a stand alone credit, rather than to suppliers. The utilities also agreed with Staff that the storage credit for Rider CFY customers should be applied on a per therm of Maximum Daily Quantity basis rather than a per customer basis.

Briefly:

J.P. Morgan Seeks Option 2 REP Certificate

J.P. Morgan Ventures Energy Corporation filed a REP application with the PUCT as an Option 2 REP, seeking authority to serve only specific customers. J.P. Morgan would meet financial requirements via an investment grade credit rating.

Maryland PSC Grants On-Demand Broker License, Levies Penalty

The Maryland PSC granted an electric broker license to On-Demand Energy and ordered the broker to pay a penalty of $100 for operating without a license in the state since 2006 (Matters, 6/12/09). The penalty was derived as the higher-of Commission assessments that On-Demand would have paid had it been licensed, or $100. Based on On-Demand's Maryland revenues ($2,863 for 2006, $5,208 for 2007, and $9,193 for 2008), the assessment would have been less than $40 total. On-Demand's license permits it to broker non-residential customers at the four investor-owned utilities as well as Choptank Electric Cooperative and Southern Maryland Electric Cooperative. Prior to licensing, On-Demand had secured contracts for five Maryland electricity customers, representing seven accounts.

Ultimate Energy Advisors Receives Texas Aggregator License

The PUCT granted Ultimate Energy Advisors an electric aggregator certificate, to pool residential, commercial and industrial customers. Principals Bobby Schiff and Arnold Felner worked for Power Brokers for five years through 2008 (Matters, 6/23/09).

Business Energy Partners Seeks Texas Aggregator license

Newly formed broker Business Energy Partners sought an electric aggregator certificate from the PUCT to serve non-residential customers. CEO Dann Day has been CFO at broker ElectYourRate.com. Business Energy Partners said it is also active in Illinois, New York, Massachusetts, Pennsylvania, Ohio, and Michigan.

MXenergy Extends Early Consent Deadline for Exchange Offer

MXenergy has extended the early consent deadline and the withdrawal deadline for its exchange offer and consent solicitation of its outstanding floating rate senior notes due 2011 until 5:00 p.m., New York City time, on July 16, 2009, in order to provide holders of Notes additional time to consider tendering their Notes to receive an early consent payment. As only reported by *Matters*, the exchange offer is integral to a restructuring plan at MXenergy (Matters, 7/2/09).

New DPUC Draft on Billing Errors Would Issue Declaratory Ruling, Affirm Prior Interpretation

A revised Connecticut DPUC draft decision would see the Department issue a declaratory ruling on the interpretation of Conn. Gen. Stat. §16-259a (billing errors), though in its interpretation the DPUC would simply affirm two recent decisions relating to the statute (including its findings in reviewing Connecticut Light and Power's billing errors). The initial draft released by the DPUC had declined to issue any declaration as to its interpretation of the statute, since the two prior decisions had addressed the statute (Matters, 7/1/09).

Kelson Withdraws Rehearing Request

Kelson Transmission withdrew its request for rehearing of the PUCT's order denying its application for a CCN for its transmission project to link the Cottonwood plant with ERCOT.

Ista Realigns Divisions

Ista North America said it has realigned its E:SO division (which includes EDI services) and Multifamily Solutions Group, and named current E:SO CEO Ruediger Neubauer as CEO of Ista North America as well. The two units will remain independent, though Ista said unified leadership will allow it to combine and consolidate certain functions.

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higher time-of-use rates during the same time period in which peak time rebates are available, it will be much easier for customers to remember when they should reduce load, hopefully avoiding any confusion that differing time periods could create, BGE added.

If the proposed peak-time program were instituted under today's generation rates, BGE said that the rebate would be $1.25/kWh of reduction. Summer generation rates would be 16.582¢/kWh on peak, and 10.690¢/kWh off-peak, with non-summer rates a flat 10.690¢/kWh. The $1.25/kWh rebate is based on the SWMAAC Net Cost of New Entry (CONE) of $176.44 per MW-day for the 2012-13 delivery year.

BGE said its peak-time rebate program is expected to lower system peak demand by about 500 MW, mitigating capacity and energy prices, and reducing transmission congestion costs.

BGE's smart metering application would also include universal deployment of 730,000 advanced gas meters throughout its territory, with the combined program cost coming to $482 million during a five-year deployment period, with several hundred million more of ongoing operating costs post deployment completion.

The new meters would meet PSC specifications as set in Case 9111, including the capability to handle a minimum of hourly meter reads, monitor voltage, accept remote programming instructions, be reconnected and disconnected remotely, communicate outage restoration events, and support for net metering and bidirectional metering.

The communication system between the meter and the customer premise via a ZigBee chip will enable a wide variety of consumer products for managing energy usage and automating other activities within the home, BGE said. BGE noted retail suppliers will benefit from the provision of more immediate and detailed information regarding their customers' accounts, and will be able to leverage the new infrastructure to offer differentiated pricing arrangements.

BGE asked that its application be approved in a timely fashion so it can begin deployment by October 1. Costs would be recovered through a surcharge prior to the inclusion of assets in base rates. Over the life of the program, the monthly surcharge would average approximately $1.24 and $1.52, respectively, for residential electric and gas customers, and would be reduced based on the award of a Department of Energy smart grid grant. BGE said that the program could potentially save electric and gas customers in excess of $2.6 billion over the life of the project.

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However, RESA said that any contract with a gas-fired generator is likely to include either a fuel price escalator or a large risk premium, because no developer is going to take on commodity risk for 15 to 20 years. Contracts with either of those two provisions would not mitigate volatility as envisioned and would not benefit customers, RESA said, recommending that the DPUC not accept any bilateral contracts with gas-fired generation.

Indeed, in earlier comments, Towantic Energy complained that United Illuminating's current bilateral solicitation prohibits the pass-through of changes in natural gas prices, as Towantic said that it is not economic for developers to bear the commodity price risk for periods longer than five years.

Ansonia Generation, which is pursuing development of a combined cycle facility, echoed Towantic's comments in a Monday filing.

"Financing to construct this project depends on the availability of a 20 year contract with one or both of the EDCs. AnGen has discussed gas pricing with several institutions, most of whom will only provide firm gas commitments for 2-3 years. Any commitments beyond that point will necessitate hedging strategies that will likely be financially burdensome to ratepayers ... AnGen does not believe that any market maker will agree to take commodity risk for 20 years, or for any significant portion thereof," Ansonia Generation said in asking that ratepayers take the risk.

Noting the steady rise in small customer migration month after month, RESA cautioned the Department against allowing too much Standard Service supply to be bought for long periods of time, as the current load may not be on Standard Service 15 years into the future. RESA noted 40% of Standard Service load shops at United Illuminating, while 32% of Standard Service load shops at Connecticut Light and Power. Given current market pricing, RESA expects migration will continue to grow appreciably over the next several months.

RESA also suggested that any load procured on bilateral contracts should be sold into the wholesale market, and credited or charged to all customers via nonbypassable surcharge. Such a mechanism will preserve proper retail price signals to encourage demand response and energy efficiency which help lower energy prices, RESA said.

RESA also stressed that all potential costs from bilateral contracts must be considered in the DPUC's evaluation, including potential stranded costs, and the cost of any transmission needed to import supplies into Connecticut.

OCC asked that it and the DPUC's consultant Levitan & Associates be involved throughout the entire solicitation process conducted by utilities. OCC reported that while UI has involved OCC in its recent solicitation, CL&P has not involved the consumer counsel.

For contracts which are not contested by OCC or Levitan, OCC envisions a streamlined approval process, but said a full review with discovery and testimony is required for contracts which OCC or Levitan feel are not in the public interest. Such a review process could take two months, OCC said. Separate "buy" and "sell" teams should be mandated at the utilities during procurements, OCC added.