Energy Choice Matters

May 20, 2009

CenterPoint Suggests Recovering Expedited Meter Read Costs Via AMS Surcharge

CenterPoint Energy has offered a novel alternative to facilitate the acceleration of the retail switching timeline in ERCOT through the use of out-of-cycle meter reads, by suggesting that the costs of additional out-of-cycle reads may be considered advanced metering system (AMS) costs, and eligible for recovery under the AMS surcharge (36536, Matters, 5,7/09).

While a Staff proposal would accelerate the switching timeline to less than seven days, there is lingering concern about the costs of additional out-of-cycle reads to accomplish expedited switches, or alternatively, the use of estimated reads in place of out-of-cycle reads to reduce such costs.

CenterPoint argued that the cost of providing an out-of-cycle meter read for customers without AMS may reasonably be considered a cost of AMS, or alternatively, a change in operating costs resulting from AMS deployment, because such out-of-cycle reads are necessary in order to begin utilizing the AMS functionality for switching.

AMS will allow the customer's meter to be read at any time without incurring the cost associated with performing a physical out-of-cycle meter read. However, CenterPoint said that in order to utilize this AMS capability, the current market model must be changed so that the standard switch occurs within a few days of the customer's request, rather than at the time of the meter read performed for billing purposes, and so that customer's REP is no longer charged for an out-of-cycle meter read.

"The change to the market model cannot be made applicable solely to customers who already have AMS, however, and instead must apply to all customers," CenterPoint reasoned.

Thus, the costs of out-of-cycle reads are essentially incurred to support the AMS-enabled faster

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NOPEC Files Complaint over Ohio Edison, Cleveland Electric Illuminating Switching Fees

The Northeast Ohio Public Energy Counsel has petitioned PUCO for a stay and expedited ruling regarding a $5 switching fee imposed per customer in the governmental aggregation pool, which may be assessed by Ohio Edison and Cleveland Electric Illuminating.

In a complaint, NOPEC said that the fee is contrary to SB 221 as well as Commission rules. Under the current supplier coordination tariff, the fee is to be assessed on NOPEC's supplier, Gexa Energy, for approximately 535,000 customers in the opt-out pool, which NOPEC said would effectively cost its customers $2.5 million.

In November, the Commission adopted revised Ohio Administrative Code Chapter 4901:1-10-32(D), which holds that, "A switching fee shall not be assessed to customer accounts that switch to or from a governmental aggregation."

Though PUCO granted rehearing of its November order, which addressed a myriad of retail market rules, no party challenged O.A.C. 4901:1-10-32(D) in rehearing requests, NOPEC said, noting that PUCO's order granting rehearing only permitted further consideration of the matters specified in applications for rehearing. PUCO ultimately adopted revised rules under O.A.C. 4901, including an unaltered 4901:1-10-32(D), on May 6. NOPEC said that the revised rules were filed with the Joint Committee on Agency Rule Review on May 18, making the earliest effective date of

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UI, CL&P Post Rates for July 1

United Illuminating posted Last Resort Service rates for the quarter beginning July 1, while Connecticut Light and Power posted retail rates for Standard Service for the six-month period beginning July 1, and the three-month period beginning July 1.

United Illuminating

Last Resort Service Generation Services Charge (GSC) in ¢/kWh
July through September 2009
Applies to Rates GST, LPT*, NUS

	Peak	Off-peak
July	9.2440	6.9590
August	9.2080	6.9930
September	8.1020	6.6040

* Rate LPT Shoulder & Off-peak price is the same

Connecticut Light and Power

Last Resort Service Generation Rates (¢/kWh)
July through September 2009

	GSC Rate	FMCC - Generation Rate	Total Generation Supply Rate
Rate 21, 39			
July	7.783	0.450	8.233
Aug.	7.707	0.450	8.157
Sept.	6.946	0.450	7.396
Rate 41, 55, 56, 57, 58			
On-peak			
July	9.708	0.450	10.158
Aug.	9.687	0.450	10.137
Sept.	8.155	0.450	8.605
Off-peak			
July	6.982	0.450	7.432
Aug.	6.981	0.450	7.431
Sept.	6.465	0.450	6.915

Rates are for customers in listed classes whose load is 500 kW and above. Customer in listed classes under 500 kW pay Standard Service charges (see next page)

Connecticut Light and Power

Standard Service Generation Rates (¢/kWh)
July through December 2009

Rate	GSC Rate	FMCC - Generation Rate	Total Generation Supply Rate
Rate 1, 5	11.962	0.450	12.412
Rate 7			
On-Peak	14.500	0.450	14.950
Off-Peak	11.000	0.450	11.450
Rates 18, 29, 30, 35, 40, 115			
	12.261	0.450	12.711
Rates 21, 119	12.276	0.450	12.726
Rates 27, 37			
On-Peak	14.327	0.450	14.777
Off-Peak	11.327	0.450	11.777
Rates 41, 55, 56			
On-Peak	14.422	0.450	14.872
Off-Peak	11.422	0.450	11.872
Rates 116, 117	10.866	0.450	11.316

BGE Recommends Continuing 20% Winter Gas Hedging Cap

Given its historic experience with winter gas supply hedging which has resulted in higher costs for customers, Baltimore Gas & Electric recommended that the Maryland PSC not order BGE to hedge any more winter supplies than the 20% cap set forth in its current Market-Based Rate mechanism, BGE said in a reply to the Commission's request for information on LDC hedging (Case 9193, first in Matters, 5/13/09).

BGE's Market-Based Rate program under Rider 2 calls for 10-20% of winter flowing gas to be hedged annually. Recently, BGE has typically been hedging 12% of supplies, but has found that hedged gas is more expensive than market rates during the winter.

Over the past three winters, BGE's hedged fixed-price contracts for flowing winter gas have cost sales customers about $20 million more than if the gas had been bought at market prices (i.e. the City Gate Index) during the winter period.

"Attempts to time the execution of such fixed price contracts has also not provided lower costs to customers," BGE said.

Fixed price gas purchased forward for the winter season has been more expensive than the actual winter market prices for five of the eight winters between 2001-2002 and 2008-2009. "The additional cost of this gas may be viewed as the insurance premium paid for some level of protection from winter price spikes," BGE reported.

For the winters between 2006-2007 and 2008-2009 alone, BGE estimates that the insurance premium above the City Gate Index was about $20.1 million.

Furthermore, gas rates that do not reflect current market prices, "deprive customers of valuable information upon which to make decisions about consumption; such rates could stifle efforts to encourage energy conservation," BGE added. To the extent that customers desire price certainty, fixed-priced gas offerings are available from third-party retail suppliers, BGE noted.

Still, given that winter futures prices appear attractive relative to the prices experienced in previous years, BGE intends to increase the amount it hedges under Rider 2 to the 20% cap. Combined with the hedged storage purchases previously ordered by the Commission, about 55% of the gas supplied to customers this winter, presuming normal weather, would not be subject to winter market price volatility, BGE said. While BGE believes that to be an appropriate amount, the LDC said that it will accept whatever level of fixed-price winter flowing gas the Commission determines will best serve the needs of customers this winter.

WGL Reaches Settlement on Hedging

Washington Gas Light also reported that it, Staff and the Office of People's Counsel have reached an agreement in principle for a settlement on its hedging program, after a prior program lapsed and WGL sought reauthorization (Matters, 2/2/09). Settlement language is still being drafted. WGL said that the stipulation will set a ceiling price above which hedging would not occur during a transition period. Due to the lapse in its hedging authority, WGL has not hedged any supply for this coming winter aside from summer storage injections consistent with the Commission's order in Case 9174.

Bohn Alternate Draft Would Increase Solar Projects for SCE and IPPs

Southern California Edison and merchant generators would each be permitted to build up to 250 MW of small-scale solar power, subject to certain conditions, under SCE's solar photovoltaic program, an alternate proposed decision by Commissioner John Bohn would hold (A. 08-03-015, Matters, 3/16/09).

SCE originally requested to build 250 MW of distributed solar in 1-2 MW installations, to fill a gap between smaller installations under the California Solar Initiative and larger projects developed to meet RPS requests for proposals.

The original proposed decision would allow SCE to build 160 MW of utility-owned solar, with 90 MW procured from independent developers via competitive bidding.

Bohn's decision would increase the total amount of the solar program to 500 MW, with 250 MW allocated to utility-owned generation, and 250 MW to merchant generators.

SCE would be authorized to build its 250 MW at a target cost of $3.50/W subject to a 10% contingency.

The 250 MW to be procured from merchant developers via competitive RFO would also be capped at prices no greater than 100% of SCE's levelized cost of electricity.

Bohn's draft would require SCE to share with developers locations on the grid where distributed solar PV will be desirable, and would direct SCE to procure about 20% of the 250 MW of merchant generation annually over a five-year period. SCE would install its owned generation at a rate of 50 MW per year.

CAISO Ancillary Services Must-Offer Requirement for RA Resources Draws Protests

The California ISO's proposal to impose an ancillary services must-offer requirement on Resource Adequacy (RA) capacity as part of its proposed standard capacity product drew criticisms from merchant generators, while incumbent LSEs argued that the mandate did not go far enough (ER09-1064).

CAISO proposed that an Ancillary Services must-offer obligation be imposed on RA Resources certified to provide Ancillary Services, in addition to the current Energy must-offer obligation. The Ancillary Services must-offer requirement would enable CAISO to optimize use of the Energy and Ancillary Services capabilities of RA Capacity in its markets, CAISO said (Matters, 5/6/09).

Calpine opposed the measure, as the expansion of RA resources' obligations is not an essential component of a standard capacity product and should be evaluated independently. Calpine argued that CAISO has not demonstrated a systemic flaw in the RA program that deprives it of sufficient Ancillary Services bids, noting that in the "relatively few" incidents when Ancillary Services bids have been deficient, the average deficiency level has been less than 10 percent for most ancillary services.

Southern California Edison, however, opposed CAISO's recommendation to exempt Use-Limited Resources from the Ancillary Services must-offer obligation. Without applying the Ancillary Services must-offer requirement to Use-Limited Resources, CAISO lacks direct tariff authority to stop such resources from improperly withholding, SCE said. San Diego Gas & Electric agreed that consumers will be "ill-served" if hydro and Use-Limited Resources that have been given credit for meeting RA requirements are not being used efficiently to provide energy and ancillary services.

CAISO's standard capacity product would not initially apply availability standards to several resources, such as demand response as well as resources whose RA Qualifying Capacity is determined by historical output from the California PUC which does not adjust the historical output data (such as wind or solar), in order to correct for the potential double counting of outages.

Western Power Trading Forum and Dynegy called the exemptions contrary to the notion of a "standard" capacity product, opposing such "discriminatory" treatment.

WPTF noted that any concerns about the double counting of forced outages are properly dealt with at the California PUC. Furthermore, while CAISO said it intends to revisit the exemptions, WPTF noted that CAISO provides no set deadline for revisiting the exemptions, cautioning FERC that the exemptions may be open-ended.

SCE opposed CAISO's proposal to only grandfather capacity contracts executed prior to January 1, 2009, from the new availability standards, rather than all contracts executed prior to the tariff's effective date. The ISO said that the earlier cutoff date is needed to prevent market participants from rushing out to enter more favorable contracts not subject to the new availability standards before FERC accepts the tariff, but SCE dismissed such concerns. Furthermore, such concerns are outweighed by the fact that contracts not grandfathered, but written and executed before the benefit of final FERC adjudication, will be subject to risks and obligations that could lead to significant disputes, SCE said.

"This uncertainty could result in parties foregoing the risk of such changes and simply not engage in any contracting or, at a minimum, result in increased cost to LSEs in order to account for unknown changes to the [standard capacity product] once it is adopted," SCE said.

The Alliance for Retail Energy Markets supported the CAISO's proposal as filed, asking FERC to approve tariff changes by June 27 to ensure that the new standard product may be in place for the 2010 compliance year.

Briefly:

Yam Energy Seeks Texas Market Entry Via Transfer of Our Energy Certificate

Our Energy, which was certified last year and completed an ERCOT test flight but is not serving customers, applied at the PUCT to transfer its REP certificate to newly formed retailer Yam Energy. Yam Energy is led by Tanweer Ahmed, who is currently President of North Coast Couriers, a leading courier service provider in California. Tom Tate, listed as COO of Our Energy, will serve as COO as Yam Energy as well. Tate has 15 years of experience in retail electric operations, in various marketing and business/product development roles for TSE Services, a subsidiary of the North Carolina Electric Cooperatives, and New York State

Electric & Gas. Iftikhar Ahmed will lead risk management at Yam Energy. Ahmed has four years of experience in wholesale purchasing and contract negotiation for natural gas and electricity for approximately 10 to 15 MW annually for MYYUM Brands. Yam Energy has contracted with EC Infosystems for EDI services, billing services, and other backoffice functions. Yam Energy would meet currently applicable financial standards via unused cash resources of at least $100,000.

DPUC Draft Would Grant Electric License to New England Gas & Electric

The Connecticut DPUC would grant start-up New England Gas & Electric an electric supplier license under a draft decision. The start-up is led by former Commerce Energy COO Michael Fallquist (Matters, 4/14/09).

TXU Among Google PowerMeter Partners

TXU Energy was among eight partners announced by Google.org for its PowerMeter electricity usage monitoring device, and the only U.S. competitive retailer chosen (Matters, 2/11/09).

Chesapeake Energy Services Seeks Md. Electric Broker License

Chesapeake Energy Services filed an application with the Maryland PSC for an electric broker license. Chesapeake Energy Services sought authority to broker commercial and industrial customers in the four investor-owned utility territories.

Suez Energy Resources NA to Hold PPL Customer Forum

GDF Suez Energy Resources NA said it will host an educational workshop on June 11, 2009, in Hershey, Pennsylvania to discuss the move to market-based rates at PPL. In addition to representatives from Suez, Eric Matheson, Chief Policy Advisor to the Pennsylvania PUC Chairman James Cawley, will speak. Suez said it currently serves over 40,000 accounts for a total contracted load of 7,150 MW.

Pepco Says Need for MAPP Line Delayed for One Year

Pepco Holdings said yesterday that a PJM review has recommended a one-year delay for the in-service date of part of the company's planned Mid-Atlantic Power Pathway (MAPP) transmission line, due to reduced demand, though the line is still critical to long-term reliability in the southern Maryland and Delmarva regions. PJM is to formally consider the analysis today. PJM's review recommended delaying the in-service date to June 1, 2014. However, PJM's review has also moved the northern portion of MAPP, from Millsboro, Del., to Salem, N.J., to its "continuing study" category, meaning the line will initially terminate at Millsboro. The change would likely reduce the total project cost from $1.4 billion to $1.2 billion, Pepco said.

FERC Approves MISO Tariff Clarifying Ability to Collect from Defaulting Parties After Uplift

FERC accepted Midwest ISO tariff revisions to clarify that the declaration of a past due amount as a uncollectible obligation or the uplift of an uncollectible obligation to other market participants does not prevent MISO from subsequently pursuing collection of a past due amount if MISO deems it to be collectible at a later date (ER09-872, Matters, 3/23/09).

Brown, Acampora Confirmed to New Terms

The re-appointments of Chairman Garry Brown and Commissioner Patricia Acampora to the New York PSC were confirmed by the New York state senate for terms expiring February 1, 2015.

Alexander Says Competitive Markets Best Opportunity for FirstEnergy Growth

Competitive markets offer the best opportunity to grow FirstEnergy in the future, CEO Anthony Alexander told investors at an annual shareholders meeting. Alexander cited FirstEnergy Solutions' governmental aggregation supply strategy as one success, while noting that the low prices for wholesale suppliers in the FirstEnergy utilities' recent Ohio default service auction are a reflection of reduced demand and excess generation in the market.

FERC Seeks Additional Comments on Smart Grid Cost Recovery.

FERC is seeking supplemental comments on its smart grid policy statement regarding rate recovery for certain smart grid investments (PL09-4). FERC noted utilities seeking Department of Energy funds under stimulus programs may seek a FERC order on cost recovery in order to make a showing of funding needed to qualify for the DOE programs.

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switching process, consistent with legislative goals for rapid AMS deployment, CenterPoint said. Such costs are appropriately covered through the AMS surcharge.

CenterPoint estimated that the expedited switching timeline will require an average of approximately 1,000 additional meter reads per business day in its territory, with the number declining over time as AMS deployment progresses.

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the rules at least 39 days from NOPEC's May 19 complaint.

Enrollment of NOPEC customers with Gexa will occur in late June or July, and NOPEC believes that the utilities intend to assess the $5 switching fee on NOPEC's supplier upon the enrollment of customers.

NOPEC argued that assessment of the switching fee would be unjust and unreasonable because of the Commission's adoption of a rule prohibiting such switching fees on governmental aggregations in O.A.C. 4901:1-10-32(D), and the failure of the utilities to file an application for rehearing of the rule. Furthermore, the imposition of the switching fee is counter to SB 221's state policy of promoting and encouraging large scale government aggregation, NOPEC said.