Energy Choice Matters
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# Half of Incumbent NiMo Residential Customers Unlikely to Switch

Nearly 40% of Niagara Mohawk commercial gas customers who have not switched suppliers say they are "somewhat unlikely" or "not at all likely" to switch, according to an annual survey of retail gas choice awareness and understanding conducted pursuant to Case 99-G-0336.

Some 47% of residential customers who have not switched suppliers say they are "somewhat unlikely" or "not at all likely" to switch, compared with 38% for commercial customers.

Residential customers in NiMo's Northeast (38.1%), Mohawk Valley (37.5%) and Capital (37.0%) regions are more likely to search for another supplier than Central (31.6%) and Northern (25.0%) region customers, the survey, conducted by Opinion Dynamics, found. Commercial customers in the Central region (44.7%) are more likely to search for another supplier compared to any other region.

The majority of both residential (76.0%) and commercial (86.7%) respondents claim that better rates would be important when deciding among suppliers. The next highest factor in choosing a supplier among commercial customers was increased reliability at 13.3%. For residential customers, increased reliability was cited by 9.6% of respondents as a factor in choosing a supplier, after rates and better overall service (15.7%).

More commercial than residential customers know how much savings they would require to switch suppliers. The savings amount cited most by commercial customers as needed to switch was 6-10%, chosen by 26.6% of customers, followed by 11-20% savings, cited by 15% of customers.

Nearly one-quarter of residential customers say that price is not a factor, and over one-third of

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# Md. PSC Issues Show Cause Orders to LDCs Over Storage Hedging; WGL Requests More Flexibility

The Maryland PSC granted a Staff request an issued a show cause order to five LDCs, directing Baltimore Gas and Electric, Washington Gas Light, Columbia Gas of Maryland, Chesapeake Utilities and Easton Utilities Commission to show why storage injections for the summer of 2009 should not be hedged now at today's lower futures prices (Case 9174).

The Commission agreed with Staff that if the LDCs fail to take advantage of current natural gas futures prices, they (and ratepayers) may lose an opportunity to lock-in costs lower than those that otherwise may be charged during the 2009-2010 winter heating season (Matters, 1/19/09).

The PSC opened an investigation to determine whether the implementation of a temporary hedging program that locks-in current natural gas prices should be mandated for the 2009 summer storage injection season, and ordered utilities to provide by February 13 data related to previous storage injections, the average price paid for injected volumes, and an explanation of why hedging through futures, options, procurement or other mechanisms should not be used for the 2009 summer storage injection season.

**WGL Hedging Petition**

Separately, WGL asked for authority to continue to operate both its winter baseload hedging program and its storage injection hedging program on a permanent basis. Both programs are in customers' interest because they reduce volatility, WGL said.

WGL also proposed several modifications to increase flexibility, including:

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## Pepco Files D.C. SOS Rates for June 1

Pepco filed proposed District of Columbia SOS rates for the delivery year starting June 1, 2009. Pepco also reported that it previously included an error in the uncollectible calculation. As a result the net uncollectibles were understated by just over $1 million. To minimize the impact on customers, Pepco proposed to amortize the correction over the next three years without a return.

**Pepco D.C. Generation Rates***

| **Rate R** | June-Oct. | Nov.-May |
|---|---|---|
| Minimum charge | $3.37 | $3.23 |
| In excess of 30 kWh | $0.11236 | $0.10761 |
| **Rate AE** | June-Oct. | Nov.-May |
| Minimum charge | $3.35 | $3.14 |
| In excess of 30 kWh | $0.11151 | $0.10470 |
| **Rate RTM** | June-Oct. | Nov.-May |
| On Peak | $0.13204 | $0.11586 |
| Intermediate | $0.11579 | $0.11317 |
| Off Peak | $0.10510 | $0.10652 |
| **Rate GSLV ND** | June-Oct. | Nov.-May |
| All kWh | $0.11250 | $0.10591 |
| **Rate GSLV** | June-Oct. | Nov.-May |
| All kWh^ | $0.12457 | $0.11594 |
| **Rate GS3A** | June-Oct. | Nov.-May |
| All kWh^ | $0.15429 | $0.14642 |
| **Rate GT LV** | June-Oct. | Nov.-May |
| All kWh, all hours# | $0.12399 | $0.11541 |
| **Rate GT 3A** | June-Oct. | Nov.-May |
| All kWh, all hours# | $0.12327 | $0.11474 |
| **Rate GT 3B** | June-Oct. | Nov.-May |
| All kWh, all hours# | $0.15429 | $0.14642 |

* All prices in $/kWh except minimum charge, which is a monthly flat fee
^ Rate did not produce price differential for kWh in excess of 6,000 kWh; Demand charge equals $0/kW
# Rate did not produce price differential based on peak usage; Demand charge equals $0/kW

## FERC Accepts MRTU Price Cap, Floor

FERC approved the California ISO's proposed price cap of $2,500/MWh and price floor of negative $2,500/MWh for LMPs, Residual Unit Commitment prices, and ancillary service prices in all of the Market Redesign and Technology Upgrade (MRTU) markets at MRTU start-up, in order to prevent severe settlement impacts of extreme prices that could result from unanticipated and unusual circumstances as the CAISO transitions into the new market (ER09-241).

However, FERC directed CAISO to include a specific sunset date of 12-months for the caps. While marketers had urged a shorter sunset date, the Commission was concerned 180 days may not give CAISO enough time to evaluate the market. "The proposed price cap and floor should not become a permanent band aid for inefficient market solutions resulting from software limitations," FERC said.

The Commission disagreed with marketers who claimed the price cap would "blunt" the market price signal associated with an LMP-based market. FERC found that the MRTU price cap level is high enough and the floor is low enough so that any impact on pricing signals should be relatively small.

In a separate order (ER09-213), FERC accepted CAISO's deferment, due to software limitations, of four operational features of MRTU: (1) enforcement of Forbidden Operating Region constraints for generating units in the real-time market; (2) unlimited Operational Ramp Rate changes for generating units; (3) procurement of incremental ancillary services in the Hour-Ahead Scheduling Process; and (4) automation of the commitment process for extremely long-start resources. FERC rejected a plea for the Northern California Power Agency to establish a section 206 investigation to re-examine the justness and reasonableness of the MRTU Tariff in light of the deferments.

## FERC Approves PJM Credit Revisions, Orders RTO to Address Bilaterals

FERC accepted a series of PJM tariff changes to reduce credit risk, but directed PJM to either file changes addressing how parties to existing bilateral contracts may protect themselves, or justify applying the changes to existing contracts (ER09-368).

The only seriously contested provision in the package of changes was PJM's proposal to clarify PJM's role in bilateral transactions to ensure that the transactions do not expose the PJM pool to the risks of defaults (Matters, 12/3/08). New tariff language stresses that bilateral transactions are "non-pool" transactions that are not transactions in the PJM Interchange Energy Market, even though physical bilateral transactions must be reported to PJM solely to record the title of power. Thus, buyers of bilateral contracts will essentially guarantee and indemnify PJM and its Members for the costs of any Spot Market Backup required if the seller defaults on its obligation to deliver energy.

AMP Ohio objected to the proposal, arguing it could result in double payment by the buyer if a buyer already has settled directly with its bilateral supplier by the time PJM bills the supplier for spot market energy used by the supplier to serve the transaction during the already-settled month. AMP also said the measure would increase risk in bilateral contracting, chilling the market and reducing competition (Matters, 12/29/08)

When applied to new contracts, FERC disagreed. Parties to a new bilateral transaction can establish payment and other terms that address any risks of double payments, such as settling the bilateral contract after the date for the seller's payments to PJM for any Spot Market Backup that may have been purchased.

"[W]e do not agree that PJM and its members should be responsible for the seller's default for Spot Market Backup that is acquired to supply a bilateral buyer's load and other obligations ... If parties make a business decision to enter into a bilateral contract, it is the responsibility of the buyer to assess the risks and protect itself through collateral terms and other contract provisions. Therefore, we do not agree that the revisions would impose an extraordinary measure of financial risk on purchasers in bilateral transactions," the Commission said.

However, FERC also found that PJM has not demonstrated how a party to an existing bilateral contract would be able to protect itself from double payment since the buyer may not be able to amend the existing collateral terms and other contract provisions. Therefore, FERC directed PJM to make a filing explaining why applying the provision to bilateral contracts executed prior to the effective date of the tariff revision (Feb. 1, 2009) is just and reasonable, or instead propose tariff revisions relating to the treatment of existing bilateral agreements.

FERC also accepted AMP's suggestion, unopposed by PJM, for PJM to modify its tariff so that PJM assigns its claim for a seller's nonpayment for Spot Market Backup to any buyer that has made an indemnification payment to PJM with respect to that seller's nonpayment.

Other changes approved by FERC include a reduction of the PJM breach cure period from three business days to two business days; a new requirement for a market participant to report collateral defaults to other PJM Members; exclusion of Financial Transmission Rights (FTR) historical activity from the two-month peak financial security credit requirement; and new FTR prompt month credit requirements.

## LSEs Oppose Accelerated RTO Settlements as Permanent Shift in Working Capital

While generators pushed for accelerated settlements in RTOs as a means of reducing credit risk, LSEs cautioned that such actions would not reduce the risk of defaults, while transferring working capital to wholesale suppliers.

In post-technical conference comments at FERC on capital in the electric industry, EPSA advocated a weekly settlement period as a means of reducing credit risk exposure. FERC should require that all RTOs shorten financial settlement periods to one week, leaving implementation details to the individual RTOs, EPSA urged (AD09-2).

But, "[c]onversion to a weekly invoicing cycle, which would only alter the frequency of payments between LSEs and suppliers in the RTO/ISO markets, would not result in an appreciable reduction in risk," the New York Transmission Owners said, since the billing cycle for the end-use customer would remain on the same monthly cycle, as is generally required by state regulatory authorities.

"With weekly settlements, LSEs would be

required to pay their wholesale energy bills weeks earlier than they receive payments from retail customers. Moreover, weekly settlements would require competitive suppliers to pay the RTO/ISO for their energy costs weeks before they settle their hedges," the Transmission Owners noted.

In addition, most wholesale contracts for fuels and power are still settled monthly, the Transmission Owners said.

Weekly settlements would not provide net market savings, Consolidated Edison Solutions cautioned. "To the contrary, the benefit to suppliers for earlier receivables is a permanent shift of working capital at the expense of LSEs that have to pay their ISO / RTO bills earlier than they either receive the revenue from retail customers or settle their hedges in the bilateral markets," ConEd Solutions observed.

ConEd Solutions suggested that advanced payments for LSEs could be used as a voluntary mechanism to reduce collateral requirements, through a pre-pay program, but should not be mandatory.

DC Energy, however, argued that moving from a 50-day settlement period to five days removes 90% of billing risk exposure.

LSEs also widely supported continuation of unsecured credit to creditworthy market participants, though some recommended stricter criteria for unsecured credit. Some market participants, such as DC Energy, have suggested eliminating the granting of unsecured collateral to investment grade companies, but LSEs argued the attendant higher credit costs would simply be borne by end users.

"The availability of unsecured credit to creditworthy market participants encourages market participation, and minimizes costs to end users," Hess Corporation said. Furthermore, the availability of unsecured credit to entities passing RTO criteria, "permits creditworthy LSEs to participate in the market on equal footing with the other market participants," Hess said.

"Given the costs of credit in today's financial markets, it would be unfair and detrimental to heap undue credit burden of the physical electric energy and capacity RTO/ISO markets upon just one market participant," Hess added. The New York Transmission Owners also opposed removal of unsecured credit limits.

APPA, citing various testimony at FERC's technical conference about the dearth of investment due to short-time price signals, argued FERC must foster a wholesale market environment that facilitates LSEs entering into long-term power supply arrangements, be they PPAs or self-build/self-supply arrangements. While APPA noted power supply decisions regarding retail electric service are the purview of state public utility commissions, it urged FERC in its collaborative with NARUC to pursue the need to support long-term PPAs.

EPSA also urged FERC to work with states to provide long-term revenue streams for generators, for both new and existing facilities. However, unlike APPA, EPSA suggested capacity markets could fill this goal as well as PPAs.

Reliant Energy countered that, "the current state of capital and credit markets will not be improved by a requirement for rate-payer backed long-term contracting as a mechanism to encourage investment," stressing FERC should continue its current approach of allowing buyers and sellers to come to voluntary commercial agreements.

Noting that mandated long-term contracts for new investment unnecessarily locks customers into potentially higher cost resources, Reliant recommended that FERC should continue to support policies that ensure a robust competitive market containing many buyers and sellers and a stable regulatory framework.

The Committee of Chief Risk Officers urged FERC to develop standards and best practices for various RTO credit policies, including: settlement cycle; number of days to post collateral; policy on unsecured credit; default allocation methodologies; and netting (payment netting, collateral netting, multilateral closeout netting, and multilateral netting by novation).

## Exelon Names Slate of Nine Directors for NRG Board

Following through on an earlier promise, Exelon announced a proposed a slate of nine "independent" nominees for election to NRG Energy's Board of Directors, at the NRG 2009 annual meeting of shareholders in May, together with a proposal to increase the number of NRG directors from 12 to 19.

If the board were expanded, and all of Exelon's nominees were seated, Exelon-backed directors would comprise just under half the board.

NRG called Exelon's actions to initiate a proxy fight, "a clear attempt to compromise the independence of NRG's Board in order to force a sale of NRG to Exelon at a price that is highly dilutive to NRG stockholders."

"Through this latest aggressive tactic, Exelon is attempting to dilute NRG's Board of Directors and NRG stockholder value, while attempting to take all the value for Exelon's stockholders," NRG added.

NRG questioned the independence of Exelon's "hand-picked" nominees and is concerned that, if elected to the NRG Board, Exelon's nominees would have inherent conflicts of interest in evaluating any transaction between NRG and Exelon or any alternative transaction.

## FERC OKs ISO-NE Policy to Link FCM, Interconnection

FERC accepted ISO New England tariff revisions, without modification, to integrate the Forward Capacity Market and the generator interconnection process, by incorporating the Forward Capacity Market's deliverability standard as the intra-zonal deliverability standard in the interconnection procedures. Under the changes, Capacity Network Resource Interconnection Service will be based on a new "first-cleared, first served" approach, relating to the Forward Capacity Market (ER09-237).

FERC dismissed protests raised by PSEG Power, which had argued that the changes undermined the property rights accorded to generators that are part of the interconnection queue, and makes participation in the Forward Capacity Market mandatory to obtain the new Capacity Network Resource Interconnection Service. PSEG objected to the ability of generators clearing the Forward Capacity Auction to pass over projects higher in the queue, based on the proposed "first-cleared, first served" rule.

However, FERC said the revised procedure and Forward Capacity Market clearing provisions address a concern with the current first-come, first-served queuing practice; specifically, the concern that a higher-queued resource -- by simply qualifying for the Forward Capacity Auction and thereafter failing to post financial assurance or withdrawing at the start price for an auction -- can effectively block out resources that could provide capacity at a lower price than the higher-queued resource. By using a first-cleared approach, the new mechanism prevents a higher-queued resource from blocking a lower-queued resource, thereby promoting market efficiencies, the Commission found.

FERC noted that the proposed "Long Lead Time Generating Facility" option provides facilities an opportunity to study and secure their costs and upgrade responsibilities for participation in the Forward Capacity Market, so that they are not disadvantaged by lower-queued resources that are able to clear in earlier auctions due to their short-term development cycles.

## *Briefly:*

**MC Squared Energy Services Submits Illinois Application**

MC Squared Energy Services, which resulted from a joint venture of Lower Electric, Rock Creek Energy Partners and Wolverine Trading announced in December, formally applied to the Illinois Commerce Commission for an alternative retail electric supplier license on Friday. MC Squared has been managing Lower Electric's 250-customer book since December, and plans to assume Lower Electric's license upon ICC approval.

**Amerex Files for Maryland Licenses**

Amerex Brokers filed applications for Maryland gas and electric licenses last week.

**Aquila, MISO Reach Agreement in Principle**

Aquila and the Midwest ISO have reached an agreement in principle resolving all outstanding issues raised by MISO in its protest of Aquila's withdrawal from the MISO Transmission Owner Agreement (ER09-414). The parties asked FERC to abate the proceeding as they finalized their agreement. In its protest, MISO sought to compel Aquila to honor all outstanding financial and other obligations to MISO, including exit fees (Matters, 1/13/09).

**FERC Accepts PJM Incremental ARR Mechanism**

FERC accepted without modification new PJM tariff language to value and assign Incremental Auction Revenue Rights (IARRs) and Incremental Capacity Transfer Rights (ICTRs) to transmission customers and merchant transmission facilities assigned cost responsibility for 500 kV and above transmission upgrades (ER09-367, Matters, 12/3/08). Customers are allocated the congestion-hedging instruments in relation to their funding of transmission upgrades which increase the Auction Revenue Rights or transfer capability of the system. The value of IARRs that become effective at the start of a Planning Period shall be determined in the same manner as annually allocated ARRs, i.e., based on the nodal prices resulting from the annual FTR auction. The value of IARRs that become effective after the commencement of a Planning Period shall be determined on a monthly basis for each month in the Planning Period, beginning with the month the IARRs become effective.

**ICC Picks Statewide Smart Grid Facilitator**

The Illinois Commerce Commission designated Erich Gunther, Chairman of engineering and software consultant EnerNex, as the third-party facilitator for the statewide smart grid collaborative.

## *NiMo ... from 1*

residential customers are unable or unwilling to identify the amount needed to switch. Of those identifying an amount, the highest rated was 11-20%, selected by 9.2% of residential customers.

For customers who have not switched, the most cited reason among residential customers was price (26.5%). For commercial customers who have not switched, the most cited reason was "don't want to switch"(15.0%), followed by price at 13.9%.

Some 84% of residential and 85% of commercial respondents feel choice is either important or very important. While choice is important to the majority of commercial respondents in each NiMo region, there have been declines in three regions compared to 2007. Since 2007, the Capital and Mohawk Valley regions are the only regions to show an increase in importance.

According to the survey, 70.1% of residential and commercial respondents are "interested" or "extremely interested" in natural gas retail competition. Interest in choice has increased among both commercial and residential respondents compared to last year, but fell short of the baseline levels from 2000, which were in the range of 75-80%.

Some 80% of residential customers and 81% of commercial customers responded that they were aware of retail gas choice. That's up from 74% a year ago on the residential side, but down from 85% for commercial customers last year. Nearly two-thirds of both residential and commercial respondents who are aware of competition understand how to choose natural gas suppliers "well" or "extremely well."

Approximately one-third of both residential and commercial respondents have not heard about switching suppliers. Of those residential respondents who have heard, communication about choice has been equally from NiMo and ESCOs (about 17% from each). Of those commercial respondents who have heard, more respondents have heard communication from other suppliers than from NiMo (24% from suppliers versus 10% from NiMo)

## *Md. Gas ... from 1*

- Expanding the time period for execution of hedging transactions to up to 36 months prior to the flow date of the hedged gas;
- Allowing for the use of financial transactions for winter baseload transactions, and
- Combining the two hedging programs.

WGL compared its request to spread out the time period under which it can purchase hedges to the approach taken with respect to Maryland electric SOS procurement (though not specifically cited, presumably Type I SOS), and said it was seeking flexibility to acquire the hedging instruments outside of time frames that have shown high, historic prices.

WGL said it would limit the volumes to be hedged up to three years in advance to 33% of volumes, with 67% of the volumes hedged up to two years in advance.