Energy Choice Matters

February 10, 2009

# West Penn Power Requests to Accelerate Residential Default Service Procurement

West Penn Power (Allegheny) petitioned the Pennsylvania PUC to accelerate its approved default service procurement plan for residential customers to take advantage of current lows in market prices.

Allegheny asked to procure its initial slice of residential load in April 2009, rather than June 2009 as scheduled. However, rather than skip the June 2009 procurement, Allegheny would also move other residential tranches forward accordingly. The result would be to procure more residential load ahead of the delivery date, with a decrease in 17- and 29-month contracts procured in 2010.

Allegheny's default service plan covers service for 29 months, beginning with the expiration of rate caps January 1, 2011. Its PUC-approved plan calls for a mix of 29-month, 17-month and 12-month contracts, along with some spot purchases, depending on customer class

Specifically, Allegheny proposed buying residential (Service Type 10) supply blocks on the following schedule:

| Term | Apr '09 | Jun '09 | Oct '09 | Jan '10 | Jun '10 | Oct '10 | Jan '12 | Apr '12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| 17-Month | 3 | 3 | 3 | 2 | 2 | 2 | | | 15 |
| 29-Month | 2 | 2 | 2 | 1 | 1 | 1 | | | 9 |
| 12-Month | | | | | | | 8 | 7 | 15 |
| Spot | | | | | | | | | 6 |

That compares to the PUC approved schedule of:

| Term | Jun '09 | Oct '09 | Jan '10 | Jun '10 | Oct '10 | Jan '12 | Apr '12 | Total |
|---|---|---|---|---|---|---|---|---|
| 17-Month | 3 | 3 | 3 | 3 | 3 | | | 15 |
| 29-Month | 1 | 2 | 2 | 2 | 2 | | | 9 |
| 12-Month | | | | | | 8 | 7 | 15 |
| Spot | | | | | | | | 6 |

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# PJM, Load Representatives File Settlement on RPM Changes

PJM, several industrials and a few municipals filed a settlement that would implement various changes to the Reliability Pricing Model, including a new Cost of New Entry that is about 10% lower than what PJM proposed in an indicative proposal filed in December (ER09-412, Matters, 1/12/09).

The Independent Market Monitor and several regulators, such as the Maryland PSC and New Jersey BPU, do not oppose the settlement. No merchant generator or independent marketer was among the settling parties or those listed as not opposing the pact.

Under the pact, Cost of New Entry (CONE) for CONE Area 1 would be $122,040/MW-year; $112,868/MW-year for CONE Area 2; and $115,479/MW-year for CONE Area 3. Citing various studies by load representatives, PJM said FERC had "substantial" evidence to approve the CONE

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## CL&P Files LRS Rates

Connecticut Light and Power filed Last Resort Service rates for the months of April, May and June with the DPUC:

| | Last Resort Service (¢/kWh) | | |
|---|---|---|---|
| | GSC Rate | FMCC-Generation (Bypassable) Rate | Total Generation Supply Rate |
| **Rate 21, 39** | | | |
| April | 7.625 | 0.550 | **8.175** |
| May | 7.576 | 0.550 | **8.126** |
| June | 7.774 | 0.550 | **8.324** |
| **Rate 41, 55, 56, 57, 58** | | | |
| **On-peak** | | | |
| April | 8.224 | 0.550 | **8.774** |
| May | 8.442 | 0.550 | **8.992** |
| June | 9.221 | 0.550 | **9.771** |
| **Off-peak** | | | |
| April | 7.384 | 0.550 | **7.934** |
| May | 7.258 | 0.550 | **7.808** |
| June | 7.192 | 0.550 | **7.742** |

Some classes may cover both Standard Service and Last Resort Service customers; rates listed are only for Last Resort Service (≥ 500 kW)

## CAPP Again Pushing for Zonal Generation Market Share Limit, Opt-Out Aggregation

PURA's current prohibition against owning or controlling more than 20% of the generation within a power region should be updated to reflect the fact that transmission constraints have created several power regions within ERCOT, the Cities Aggregation Power Project said in releasing an 86-page history of the Texas deregulated market, and recommending changes to lower rates. Accordingly, the generation limit should be 20% of capacity in a congestion zone, rather than the entire ERCOT system, CAPP said.

Arguing that the ERCOT market is not fully competitive, CAPP alternatively suggested a return to a single ERCOT-wide market, abandoning the use of separate congestion zones to set wholesale spot energy prices. A single-price market would bring ERCOT more in line with the language of SB 7, which never contemplated separate zones within ERCOT, CAPP contended.

The cost of relieving transmission congestion in the recommended ERCOT-wide market should be based on production costs and spread in a postage-stamp style to all those who procure power, with a uniform price for relieving congestion regardless of geographical location, CAPP said. The nodal market, which CAPP argued should be scrubbed, will conversely lead to higher prices in many parts of Texas, CAPP said.

Market abuses have remained "pervasive and uncorrected," CAPP alleged, arguing market participants harmed by such anti-competitive behavior should be given the right to participate in enforcement actions by regulators. Lawmakers should demand more accountability from ERCOT, CAPP added.

CAPP reiterated prior calls for opt-out municipal aggregation, citing the "unworkable" nature of opt-in programs.

CAPP recited previous arguments, relying on average, all-in Energy Information Administration data, showing Texas rates under deregulation have gone from below to above the national average, and are rising faster than those in other states. The aggressive build-out of wind power in West Texas will drive up transmission costs for all Texans and create new electric reliability challenges, CAPP noted.

The Association of Electric Companies of Texas, however, noted that the current lowest price offers in each TDSP area are lower than the inflation-adjusted electric prices available prior to the beginning of competition, even as inflation-adjusted natural gas prices have increased by 160 percent over the same time period.

Furthermore, in three of the competitive service areas, prices are now available that are lower than the pre-competition prices, even without adjusting for inflation, AECT said.

According to AECT, the lowest residential rate at CenterPoint, AEP Texas North, and Texas New Mexico Power are below 2001 levels:

**AEP Texas Central**

| | |
|---|---|
| 12/2001 rate: | 9.6¢/kWh |
| Today's lowest offer: | 10.4¢/kWh |

**AEP Texas North**
12/2001 rate: 10.4¢/kWh
Today's lowest offer: 10.0¢/kWh

**CenterPoint Energy**
12/2001 rate: 10.4¢/kWh
Today's lowest offer: 10.3¢/kWh

**Oncor**
12/2001 rate: 9.7¢/kWh
Today's lowest offer: 9.8¢/kWh

**TNMP**
12/2001 rate: 10.6¢/kWh
Today's lowest offer: 9.5¢/kWh

Current pricing based on 2/6/09 Power to Choose prices, as reported by AECT.

## MISO Says Delay in RSG Resettlement "Reasonable" But Urges Quick Resolution

The Midwest ISO told FERC it would be "reasonable" to "briefly" defer the completion of the resettlement of Revenue Sufficiency Guarantee (RSG) charges lying outside of the regular resettlement timeline pending rehearing requests of a November 10 order which applied the charges to virtual supply offers dating back to August 10, 2007 (Matters, 11/12/09).

However, MISO urged FERC to quickly act on those rehearing requests (and its compliance filing) to obviate any uncertainty regarding the resettlements to be performed pursuant interim refund allocation methodology adopted by the November 10 order.

Several financial marketers have sought a stay in the resettlement pending rehearing requests. The millions of dollars involved and the impact of resettled charges in increasing marketers' collateral requirements have already caused two power marketers to default on their MISO agreements.

MISO argued that neither the financial impacts of FERC's order on virtual traders, nor the pending rehearing requests, require a stay in the resettlement process, but conceded a stay is reasonable to minimize the risk of having to unwind the resettlements should FERC change its order on rehearing.

Still, MISO stressed that deferring the resettlement too long would result in increased interest charges, and would extend the market's credit exposure, if the Commission eventually reaffirms the November 10 order.

DC Energy, supporting an earlier motion for stay and rehearing filed by several financial marketers, stated, "When a Commission order rapidly pushes some market participants into insolvency, bankruptcy, default, lay-offs and exiting the ISO markets; causes lost transactions for which there is no economic redress; and causes a 68% drop in relevant market activity which is critical for efficient markets, then justice demands a prompt reevaluation of the impacts of the Commission's actions and whether the order is on solid evidentiary and legal ground."

The November 10 order "has dealt a blow to market confidence" and "sent a signal to market participants to refrain from investing in Commission-jurisdictional, competitive markets because they will not be treated rationally," DC Energy said, reiterating arguments made throughout the case that MISO lacks cost justification for allocation of real-time RSG charges on virtual supply offers.

## FERC Orders NYISO to Provide More Info on Modeling Error

FERC ordered the New York ISO to provide greater detail on a system modeling error (Matters, 1/2/09), declining at this time to rule on a waiver request from the NYISO, which the NYISO had sought to avoid retroactively changing prices or settlements (ER09-405).

On December 11, NYISO submitted a filing to notify FERC of a system modeling error in its Security Constrained Unit Commitment (SCUC) software that affected certain day-ahead market schedules and prices. Transmission owners opposed the waiver, arguing more information on the error, which caused $7.4 million in net uplifts, was needed. Market participants also reported that the NYISO was slow to inform stakeholders of the incorrect modeling.

FERC agreed that more data is needed, and directed NYISO to provide an analysis of the error's effect on prices, interface flows, schedules and limits, and related information, as well as all the information regarding what the erroneous inputs were, and the results of market simulations with the corrected inputs.

NYISO should also discuss with its market participants whether any course of restitution is feasible, FERC said. While taking no position on the waiver request, FERC noted that while it is mindful of the fact that NYISO might not be able to reconstruct exactly what would have occurred in the market had the error not occurred, that fact does not excuse the Commission from seeking a reasonable estimation of such effect in order to permit some type of remedy.

Furthermore, the 10-month delay in the NYISO formally reporting the error to FERC "concerns" the Commission, FERC said. Accordingly, FERC required NYISO to file a report explaining: (1) when and how the error was discovered; (2) why NYISO did not self-report the error to the Commission's Office of Enforcement; (3) whether NYISO notified its market monitor of the tariff violation (and when), or if the market monitor was otherwise aware of it; and (4) the steps NYISO took in informing its market participants, stakeholder committees, and the Commission of the error.

The Commission agreed with stakeholders regarding the importance of NYISO promptly informing market participants when it discovers a modeling error that has an impact on the NYISO markets, and of the nature of its corrective action. Therefore, FERC directed NYISO to develop procedures for: (1) early notification of stakeholders and stakeholder committees of possible errors affecting NYISO markets; (2) timely follow-up and detailed explanations regarding errors; and (3) greater transparency and heightened responsiveness to stakeholders and appropriate committees.

FERC denied a request from Alcoa to consider the modeling error in conjunction with FERC's investigation of circuitous transmission scheduling around Lake Erie, which both resulted in market uplifts. FERC found the modeling error to be unrelated to the Lake Erie investigation, stating that the mere fact that both may have resulted in uplift charges is not sufficient reason to consolidate the matters.

# *Briefly:*

### Usource Sales Margin Flat in Fourth Quarter

Sales margin at broker Usource was flat year-over-year for the fourth quarter of 2008, at $0.9 million, parent Unitil reported in an earnings statement. For the year 2008, Usource sales margin inched higher to $3.8 million from $3.7 million a year ago. Unitil Corp. reported earnings applicable to common shareholders of $9.6 million for 2008, up from $8.6 million a year ago.

### True Electric Files for REP Certificate

True Electric, LLC, d/b/a New Century Power, applied for a REP certificate at the PUCT, though it's apparently the same legal entity which received a certificate in 2007 although with new officers and principals. The "new" True Electric, LLC lists the same formation date (March 13, 2007) as the REP True Electric, LLC which was certified October 15, 2007 in docket 34713. Nevertheless, the new REP's filing was for a new certificate rather than an amendment or transfer. The officers at the new True Electric are all principals at oil and gas firm New Century Exploration. The exploration and production firm's president, Phil Martin, will serve as CEO of True Electric. True Electric would meet PUCT financial qualificationd via unused cash resources of at least $100,000.

### Texas Electricity Aggregation Seeks Aggregation License

Texas Electricity Aggregation LLC applied for an aggregator license at the PUCT, applying to pool commercial and residential customers. Most aggregation will be commercial, though it may aggregate multi-family dwellings and also residential accounts of employees of its commercial customers, as an employee benefit.

**D.C. PSC Issues Updated NOPR on Affiliate Rules**

The District of Columbia PSC issued an updated NOPR of utility affiliate rules, covering regulations for logo use and equitable treatment of suppliers, and restrictions information sharing (FC 1009).

**LPB Energy Management Reports 12 Billion kWh on Active Contracts**

LPB Energy Management said yesterday it has surpassed 16 billion kilowatt-hours of electricity under contract since the company's founding in 1999, with over 12 billion kWh on active contracts.

**20% Wind for East Would Cost $80 Billion in Transmission**

Over $80 billion in transmission would be needed for the Eastern Interconnect to obtain 20% of its power supplies from wind power by 2024, according to the Joint Coordinated System Plan, developed by a consortium of several RTOs and regional reliability councils. Obtaining 5% of energy supplies from wind would require $50 billion in transmission, the study found. The 20% wind scenario would include $1.1 trillion in total generation capital costs, while the 5% wind scenario would include $700 billion in generation capital costs.

## *Allegheny... from 1:*

Allegheny did not seek to alter the procurement schedule for the three C&I categories in its plan.

The default service plan allows for modification of the procurement schedule based on a Commission finding that market-altering events justify a change. Discussion of the provision during the PUC's review of the plan mainly centered on postponing procurements to avoid extra-market events, such as a Gulf hurricane. However, Allegheny argued that the "current, unmistakable downturn" in generation prices warrants an accelerated procurement schedule under the provision.

Allegheny argued that it is not trying to "time the market" or create an actively managed default supply portfolio through its proposed acceleration.

Allegheny sought an expedited review of its petition, stating it needed approval by early March to conduct a procurement in April. The Office of Consumer Advocate supports Allegheny's proposal, Allegheny told the PUC.

## *RPM ... from 1:*

figures, which are higher than current CONE values but 10% lower than originally proposed.

The settlement would direct PJM to convene a stakeholder process to develop an automated Net CONE adjustment procedure to replace the existing provision regarding formulaic changes to CONE and provisions for triennial review of the shape and parameters of the Variable Resource Requirement (VRR) Curve. PJM would be required to file tariff language for the automated Net CONE adjustment by September 1, 2009, for implementation beginning with the Base Residual Auction conducted for the 2013-2014 Delivery Year. PJM would also hold stakeholder talks to review the current CONE Areas and whether new areas should be defined.

The current Minimum Offer Price Rule would be eliminated under the settlement. Instead, the Independent Market Monitor would review offers to determine: (1) whether a sellers' new generation resource offer into RPM would result in a significant decrease in the price when compared to the price that would have otherwise resulted from a competitive offer; (2) whether the seller has an incentive to reduce the RPM auction price; and (3) whether such an offer is an effort to exercise market power.

If the Independent Market Monitor makes such a determination, it would report it to PJM, and PJM would seek expedited relief at FERC. PJM would delay clearing the auction pending the Commission's decision on the matter.

The settlement would maintain PJM's proposed 2.5% target for its Short-Term Resource Procurement for the 2012-2013 Delivery Year, under which 2.5% of demand would be held back from the Base Residual Auction in order to be served by resources would short lead times, such as demand response, via incremental auctions. However, PJM would subsequently report on the results of the Short-Term Resource Procurement Target and the level of participation of short-term resources in incremental auctions, the promotion of a competitive capacity market, and the maintenance of reliability. Based on such analysis, PJM would recommend changes to the Short-Term Resource Procurement Target if needed.

RPM's New Entry Pricing Adjustment, which offers pricing assurance to certain new generation resources, would be expanded to seven years under the pact -- longer than the current three years and the originally proposed five years. While some capacity developers argued for a 10-year commitment, PJM noted that developers' needs for price assurances must be balanced against the burden on loads of out-of-market payments.