Energy Choice Matters

August 29, 2008

Two Advanced Metering Plans Approved by PUCT

The PUCT approved two advanced metering settlements yesterday: Oncor's system-wide AMS deployment and CenterPoint Energy's accelerated Advanced Meter Information Network program.

Chairman Barry Smitherman said Oncor's large roll-out was "extremely exciting" and called the monthly $2.21 fee for residential customers an impressively low number. With savings from smart meters projected at 15-20% of bills, all customers have the opportunity to save money given the low fee, Smitherman pointed out, calling Oncor's plan a win-win.

Under the plan, Oncor's advanced meters, back-office systems, and work processes will have the capability to support Time-of-Use functionality by May 1, 2009 for any ERCOT-approved Time of Use Profiles existing on August 8, 2008 (Matters, 8/12/08). Oncor will be able to support prepaid service (consistent with Substantive Rule § 25.498) by June 1, 2009 through the use of interim solutions and processes, and will support HAN functionality between one device in the home that is enabled with the ZigBee Smart Energy Profile and the advanced meter by March 31, 2009 through the use of interim solutions and processes.

Oncor's plan includes $15.1 million in customer education on smart meters and their capabilities.

CenterPoint's AMIN program allows REPs to fund accelerated deployment of advanced meters up to a 125,000-meter cap, with each participating REP assigned meters on an ESI ID share basis (Matters, 7/25/08).

CenterPoint's Advanced Metering System deployment plan, initially proposed to feature 250,000 meters, remains abated pending settlement negotiations in 35639. One of the issues under consideration is expanding deployment to occur on a system-wide basis.

Systematic Inefficiencies Persist in ERCOT, But Market Found to be Competitive

A Potomac Economics ERCOT report, "generally confirms prior findings that the current market rules and procedures are resulting in systematic inefficiencies," but noted improvements in a number of areas over the results in prior years, concluding that the market, "performed competitively in 2007."

Balancing energy market prices were 2% higher in 2007 than in 2006, Potomac noted in its State of the Market report. While the average natural gas price in 2007 increased 4% over 2006 levels, fuel prices alone do not explain all of the price changes, Potomac said, pointing to the increased offer cap of $1,500/MWh.

However, the increased offer cap, meant to produce higher prices during shortage conditions, was not always effective in achieving the intended outcome, Potomac reported.

Efficacy of the Scarcity Pricing Mechanism was challenged by:

- Frequent out-of-merit deployments by ERCOT during declared short-supply conditions;
- The reliance on market participants to submit offers at or near the offer cap to produce scarcity level prices during legitimate shortage conditions; and
- A strong positive bias in ERCOT's day-ahead load forecast that tended to regularly commit online resources in excess of the quantity required to meet expected demand and operating reserve requirements.

Potomac reported that prices during 108 shortage intervals in 2007 ranged from $40/MWh to the offer cap of $1,500/MWh, with distinct offer thresholds evident at about $300/MWh and $600/MWh. The widely varied pricing outcomes in identical shortage conditions show that relying upon the submission of high priced offers by some market participants to produce scarcity prices during

... Continued Page 5

PUCT Opens Rulemaking for Comprehensive Review of Disconnect Protections

The PUCT voted to open an orderly, deliberate rulemaking concerning customer disconnection protections meant to prevent the need to address protections on an emergency basis every summer.

Given that the current protections were themselves the result of a deliberate process meant as a permanent response to emergency moratoriums in 1998 and 2000, it remains to be seen if any rules can be crafted which will prevent the near-annual calls for extra summer protections given unique circumstances of that particular summer (e.g. record high prices or record heat).

Newly sworn Commissioner Donna Nelson, while agreeing protection is needed for the most vulnerable customers, stated she would prefer to let the competitive market solve issues, voicing a concern that the Commission should not perpetuate the notion that it's the government and is going to step in. Instead, REPs need to step in and solve problems.

Nelson stressed that any rule coming from the investigation should be measured in scope and duration, and shared the view of Chairman Barry Smitherman, as articulated in a memo (Matters, 8/28/08), that deferrals may not benefit customers when they simply allow customers to build up more debt.

Smitherman reiterated that it doesn't make sense to say that all 5.5 million residential customers in ERCOT don't have to pay their bills during the summer. Smitherman, noting that some customers enrolled in deferral plans have switched REPs before fully paying their debt, doesn't believe any legislators think that it's right for customers to be permitted to switch when they still owe money on a deferred payment plan.

Public Counsel Don Ballard welcomed a permanent solution and suggested that the PUCT should set a minimum protection floor, with REPs offering additional protections as a competitive advantage.

RG&E to Implement Fixed Non-Bypassable Charge as Part of FPO Changes

Rochester Gas & Electric was ordered to lower the conversion factor of its Fixed Price Option to 116.9% with a 4 mill/kWh adder in changes meant to harmonize the FPO with Commission policy goals and the FPO offered by sister utility NYSEG (03-E-0765).

The PSC voted on the order last week in a move meant to transition RG&E away from offering an FPO (Matters, 8/21/08), but a written order listing specific provisions was issued yesterday.

RG&E shall bear the risk of loss on the FPO, and earnings above a threshold of $6 million shall be allocated 85% to ratepayers and 15% to shareholders. The $6 million figure was derived by scaling down the $10 million threshold for NYSEG to the smaller-sized RG&E.

RG&E is to also implement a non-bypassable wires charge, reconciled annually, which should enable customers to compare commodity offerings from the utility and ESCOs more accurately.

RG&E's outreach materials regarding the FPO are to prominently display comparisons between RG&E's FPO prices during the past three annual periods to the utility's variable prices during those periods, and shall inform customers that FPO pricing arrangements are also available from ESCOs, consistent with the suggestions from several of the Commissioners at last week's regular session.

"Besides yielding a rate that is just and reasonable, these changes to RG&E's FPO will better facilitate retail access in RG&E's service territory than would occur under the existing FPO," the order stated.

RG&E may not offer the FPO after 2009 without explicit Commission approval, and must file by March 1, 2009 if it wants to continue the program for 2010.

California PUC Dismisses Concerns Over LTPPs' Relationship to Competition

The California PUC brushed aside concerns raised by competitive market advocates relating to the rulemaking for IOUs' 2010 long-term procurement plans (LTPP), with President Michael Peevey noting that it would be, "imprudent to assume at this time that other market structures will obviate the need for LTPP-authorized procurement and delay the timely development [of] 2010 LTPP policy guidance," in a scoping ruling issued yesterday (R. 08-02-007).

Competitive advocates had argued that the integrated resource plans would push the Commission back to the utility investment paradigm, but Peevey reasoned that the LTPPs are needed to provide the IOUs with clear direction and a set of expectations for the next round of plans, in the event that the LTPP continues to be a primary vehicle for acquiring new generation.

Although market structures for various resources are being debated in several other cases, IOUs will still need a robust planning process to effectively implement various policy mandates for their bundled customers regardless of what the Commission decides on market mechanisms in other proceedings, Peevey observed.

While a review of customer risk tolerance remains part of the investigation, Peevey ruled that the Commission would wait for Pacific Gas and Electric to complete a similar risk study for its gas customers before instituting a Commission study on electric customers' risk preference. That decision to wait will mean risk tolerance issues will be punted to Phase II of the proceeding.

Peevey conceded that competitive market advocates had raised an "excellent question" about the possible conflict between adopting a more stable, though pricier, supply portfolio (as contemplated by studying customer risk appetite) and Commission goals for demand response and energy efficiency through approaches including dynamic pricing.

Nevertheless, the Commission will still study customer risk tolerance despite marketer advocates' concerns, but said it will give due consideration to marketers' arguments when evaluating the study results.

Peevey's ruling sets several schedules and workshops on various issues in the case, including on Standardized Resource Planning Practices and MRTU-Related Procurement Implementation Issues.

Green Mountain Energy Details Acquisition Costs of FP&L Program

Green Mountain Energy vigorously defended its management of the discontinued FP&L Sunshine Energy program yesterday, telling the Florida PSC that it spent $5.5 million, or nearly half of program revenues, to buy RECs and develop solar projects (Matters, 7/30/08). The 20% figure quoted by the PSC as going towards green projects ignores the nearly $3 million in ongoing obligations Green Mountain has under its solar development contracts, Green Mountain said.

However, the most salient points for retail marketers is information relating to marketing and acquisition costs of an alternative to a default utility product disclosed by Green Mountain.

Green Mountain reported that on average it took 20 months to break even on new customers, who paid $9.75 for 1,000 kWh of renewable energy.

Marketing and sales costs over the nearly five-year length of the program were $5.8 million, or 52% of $11.3 million in revenues. Marketing costs were in the range of $1.7 million in the first two years of the program, then declined to just under $1 million for 2006 and 2007.

By the program's end this July, Green Mountain had enrolled 38,308 customers over nearly five years.

Below is a breakdown of average cost per sale by channel type:

Channel	**Average Cost per Sale 2004 - 2008**
Storefronts/Events	$167
Bangtails	$124
Telemarketing	$115
Direct Mail	$108

The only two channels that worked well were direct mail and bangtails, Green Mountain said, and those two channels had become key in the program's annual marketing plans since 2006.

Direct sales, with tables at targeted events, high-traffic venues (such as sponsorship/exhibit booths at Miami Dolphins and Miami Heat games and the Palm Beach County Boat Show), and at retail storefronts and shopping centers, were used for the first year and a half of the program. While the channel was effective, high churn rates of customers signed up through the direct sales channel did not justify the investment, and direct sales were ended after 2005.

Green Mountain conducted more than 50,000 hours of telemarketing in 2004 and 2005 at a cost of over $1.2 million, including $900,000 in payments to telemarketing vendors. While telemarketing accounted for approximately one-third of all program sales from 2004-05, the channel's performance suffered as the telemarketers ran out of new prospects to call, leading to lower conversions and increased per-sale costs. The churn rate for telemarketing sales proved to be significantly higher than other channels, Green Mountain added, and the channel was dropped after 2005.

Since 2004, Green Mountain has conducted 13 direct mail campaigns with 200,000 to as many as 575,000 pieces of mail sent with each campaign for an overall total of 3.6 million pieces of mail. Costs associated with direct mail included creative services, paper, envelopes, postage, mailing house fees, sales processing, and mailing lists purchases. Green Mountain paid a printing vendor more than $1.1 million for postage and printing and spent heavily on targeted mailing lists since they are critical to the success of a direct mail campaign. More than $163,000 was spent on targeted mailing lists and related consulting.

Bangtails on FP&L bills were used, on average, four times a year, with a total of 38 million sent. Payments to FP&L's envelope vendor totaled $960,000, while other expenses included costs of creative and design services, copy writing and sales processing.

Bill inserts were sent to FP&L's entire residential customer base of approximately 4 million accounts in February and June of 2004. Green Mountain paid FP&L approximately $63,000 for the bill insert space, mostly representing the cost of competing for bill insert space with other FP&L programs and vendors. In 2007, Green Mountain conducted two email marketing campaigns to FP&L residential customers, paying the utility $3,320 for the cost of sending the emails through its server.

At the time that the PSC terminated the program, Green Mountain and FP&L were developing lower cost channels, such as email campaigns, inbound service connects call center sales, and an online service connect web site. Green Mountain had expected those costs to be approximately one-third the cost of the direct mail, bangtails, direct sales and telemarketing initially used to launch and build the program.

To compare with marketing strategies, approximate customer count was 10,700 by the end of 2004, 23,300 by the end of 2005, 28,700 by the end of 2006 and 37,200 by the end of 2007.

Breakdown of Green Mountain spending:

RECs	$2.7 million
Solar Projects	$2.8 million
Marketing/Sales	$5.8 million
Administration	$1.4 million
Direct/Bad Debt	$0.6 million
Total spending:	$13.3 million

Total spending included a $2 million up-front investment by Green Mountain on marketing that will now not be recovered. Total revenues were $11.3 million

Green Mountain noted that marketing costs were less than $1.50 per each of FP&L's total 4 million residential customers. But when considering the 38,308 enrolled customers, marketing and sales expenses were $151/customer.

Green Mountain also pointed out that the Sunshine Energy program was priced significantly below the national average of other utility green power programs, and lower than other Florida programs:

- National average price: 2.12¢/kWh
- TECO (200 kWh block): 2.5¢/kWh
- City of Tallahassee: 1.85¢/kWh to 11.6¢/kWh
- Sunshine Energy price: 0.975¢/kWh

Florida customers would be hard pressed to find 1,000 kWh of carbon offsets or RECs in the retail market for less than $15, Green Mountain said, while its price was $9.75 for 1,000 kWh.

Briefly:

PPL Proposes to Ladder Mass Market Supply Contracts After 2010

PPL filed a default service procurement plant for the 2011-14 timeframe with the Pennsylvania PUC under which mass market customers would be served on 12 to 24-month laddered contracts while large C&Is would be subject to hourly pricing. For residential and small commercial customers, PPL would procure power four times a year, beginning in the third quarter of 2009.

Some 90% of the portfolio would be composed of 12 or 24-month contracts, with the remainder composed of hourly spot purchases. Such laddering is meant to reduce volatility and exposure to severe market conditions, as occurred at Pike County Light and Power a few years ago. An independent evaluator would be used for procurements.

Blumenthal Now Investigating MXenergy

Connecticut Attorney General Richard Blumenthal is investigating the billing and marketing practices of MXenergy after several customer complaints, coming on the heels of the start of a DPUC investigation (Matters, 8/27/08). Blumenthal alleged that MXenergy used introductory rates to, "lure consumers into their service, but followed by outrageously expensive rates -- without warning -- after the introductory rate ends." According to Blumenthal, "Consumers have also reported problems getting out of the expensive MX Energy service after being ambushed by surprisingly high rates."

Green Mountain Offers Expanded Deferral Plan

As tipped Wednesday by PUCT Chairman Barry Smitherman (Matters, 8/28/08), Green Mountain Energy formally announced a voluntary summer bill payment assistance program for its low-income residential electricity customers in Texas. Green Mountain is offering a four-month deferred payment plan for LITE-UP eligible customers who make an initial payment of $100 or the amount of their current bill, whichever is less.

Energy Services Group Files for Two Additional REP Certificates

Energy Services Group has applied for two additional REP certificates, for TexRep3 (Shogun Power) and TexRep4 (Busheido Energy). Both REPs listed unused cash resources of at least $100,000 to meet financial qualifications. Energy Services Group currently holds certificates for TexRep2 (Vigor Power) and ESCO1 (Elan Energy).

PECO Lowers Gas Rate

PECO is lowering its natural gas commodity rate, effective Sept. 1, from $1.68/ccf to $1.59/ccf due to a projected decrease in gas supply costs in the wholesale market

PUCT OKs RPS Opt-Out Proposal for Publication

The PUCT approved Staff's proposal for publication regarding the process for transmission-level voltage customers to opt-out of RPS obligations (35628, Matters, 8/28/08).

Calpine Inks PPA with TVA

Calpine signed a three-year, 500-MW PPA with the Tennessee Valley Authority, with power sourced from the IPP's Morgan Energy Center located in Decatur, Ala.

ERCOT ... *from 1*

shortage conditions was "rather unreliable" during 2007, Potomac said.

The existence of a "strong and persistent" positive bias in ERCOT's day-ahead load forecast in 2007 had the effect of producing an inefficient over-commitment of resources and depressing real-time prices relative to a more optimal unit commitment, Potomac added.

Because of the inefficiencies associated with a persistently high day-ahead load forecast, Potomac recommended that ERCOT review the causes of the positive bias in its day-ahead load forecast, and explore potential changes to its reserve procurement policies and its day-ahead and supplemental unit commitment procedures.

More reliable and efficient shortage pricing could also be achieved by establishing pricing rules that automatically produce scarcity level prices when defined shortage conditions exist on the system, Potomac suggested. Ideally, operating reserve demand curves would be implemented in conjunction with real-time co-optimization of energy and reserves, although the latter is not an absolute prerequisite.

Estimated net revenue was insufficient to support new entry for either a natural gas combined-cycle generator, or a simple-cycle gas turbine during 2007, Potomac calculated. Net revenue for coal and nuclear units remained above the levels required to support new entry. Excess capacity (with a 14.6% reserve margin) was one of the major reasons for the net revenue outcomes.

Potomac found that the ERCOT wholesale market performed competitively in 2007. A pivotal supplier analysis indicated that the frequency with which a supplier was pivotal in the balancing energy market decreased significantly in 2007 compared to 2006, from 21% to less than 11% of hours. Over 92% of the market's price spikes occurred during intervals with less than 500 MW of available Up Balancing Energy Service remaining, up from 84% a year ago, trending toward expected outcomes under a competitive market.

Analyses of potential physical and economic withholding did not indicate significant concerns in 2007, Potomac reported. The pattern of un-offered capacity, which is consistent across all load levels, does not raise significant competitive concerns or indicate strategic behavior to withhold more capacity under higher load conditions.

The levels of interzonal congestion rose considerably to $114 million in 2007, which reflects an increase of $45 million from 2006. The spike was the result of more frequent congestion on the North-to-Houston, North-to-West, and West-to-North Commercially Significant Constraints, as well as increased shadow price caps. The aggregated shortfall in Transmission Congestion Rights revenue, which had to be uplifted to the market, also grew considerably to $61 million in 2007, up from $7 million in 2006.

ERCOT continues to experience a clear relationship between the net balancing energy deployments and the balancing energy prices, which is not expected in a well-functioning market.

Such pricing patterns, consistently observed for several years, raise significant efficiency concerns regarding the operation of the balancing energy market. However, the nodal market will provide for a comprehensive solution to such operational issues, Potomac said.

The wholesale market should function more efficiently under the nodal market design by providing better incentives to market participants, facilitating more efficient commitment and dispatch of generation, and improving ERCOT's operational control of the system, with congestion on all transmission paths and facilities managed through market-based mechanisms, rather than non-transparent, non-market-based procedures.

"In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers," Potomac concluded.

ERCOT manages over-supply of Loads Acting as Resources in the responsive reserve market by relying upon administrative rules rather than prices to ration the product, an inefficient procedure that leads to excessive reliability costs for consumers, Potomac said.

To improve the efficiency of responsive reserve pricing and incentives for suppliers, ERCOT should impose two responsive reserves constraints in the ancillary services auction:

(i) that the responsive reserves procurement (including bilateral schedules) be greater than or equal to 2,300 MW, and

(ii) that the responsive reserves procurement from LaaRs (including bilateral schedules) be less than or equal to 1,150 MW.

The clearing price paid to generators would be equal to the shadow price of the first constraint only, while the clearing price paid to LaaRs would be equal to the shadow price of the first constraint minus the shadow price of the second constraint (a single price would result if the LaaR constraint is not binding). Such a modification has previously failed to pass stakeholder review.