Energy Choice Matters

October 19, 2009

DPUC Draft Would Require Reporting on Voluntary Renewable Sales

Connecticut electric suppliers would be required to report on their voluntary renewable sales annually in addition to reporting on RECs procured to meet the RPS, under a draft decision issued by the Connecticut DPUC which evaluates each load serving entity's compliance with the RPS for the year 2007.

The draft would require each LSE, coincident with their annual RPS report, to file:

a. A list and description of all voluntary renewable energy or "green" options or programs offered to Connecticut in the applicable year, including the percentage of voluntary renewable sources offered in each program;

b. The number of customers who enrolled in each such program and the total number of all the customers enrolled in all the programs;

c. The total number of MWh sold to customers in each program;

d. The calculation showing the number of RECs in each Class needed to meet the voluntary programs;

e. The number of RECs procured, shown separately by Class; and

f. Evidence to support the REC procurement, such as NEPOOL GIS reports.

The draft would impose the voluntary renewable reporting requirement after noting several suppliers submitted RPS reports showing procurement of excess RECs for the 2007 compliance year. However, there is no data in the record to determine why the LSEs procured extra RECs or whether the LSEs procured extra RECs to satisfy their voluntary green programs, the DPUC noted.

The draft found that of 16 companies serving load in 2007, four (Connecticut Light and Power, Constellation NewEnergy, Dominion Retail, and Strategic Energy [now Direct Energy Business]) met

Continued P. 7

West Penn Power Reports Prices from October Default Service Procurement

Allegheny Power's (West Penn Power) most recent procurement of Pennsylvania default service supplies for the period beginning January 1, 2011 produced an average weighted retail generation price of $65.29/MWh for residential customers. For non-residential customers, the average weighted retail generation price was $67.24/MWh.

Included in the average weighted retail generation price are energy, capacity, Pennsylvania gross receipts taxes, line losses, renewable energy requirements, ancillary services and other provisions.

Averaging the three residential solicitations to date (which have procured 60% of requirements), the average weighted generation rate is $71.41/MWh. For the two non-residential procurements to date, the weighted average generation rate is $70.50/MWh. In auctions held to date, the percentage of supply purchased for small and medium non-residential customers for 2011 is 24% and 22%, respectively.

Competitive affiliate Allegheny Energy Supply Company was awarded all five contracts in the October procurement, one of six suppliers submitting bids. Allegheny Supply estimated that the

Continued P. 8

Solomons to Hold Electric Hearings in 2010

Texas House State Affairs Chairman Burt Solomons announced that he will hold a series of public interim hearings in 2010 to elicit public response on several topics related to electric deregulation. The hearings will be in addition to hearings held by the Sunset Advisory Commission on the PUCT. In a letter to the *Dallas Morning News*, Solomons said that the hearings will seek public input on:

- Are current electric rates reasonable?
- Do electric consumers need additional protections to challenge rate increases?
- Do low-income and elderly electric customers have sufficient protections?
- Are the state agencies responsible for oversight of electricity fulfilling their purpose?
- Do electric consumers in deregulated areas have true choices?
- Is Texas investing enough in "green" technologies for electric power generation?
- Is Texas headed in the right direction to meet its growing population's energy needs?

Md. PSC Refers Allegheny Warrior Run Reactive Power Question to Hearing Examiner

The Maryland PSC referred to a hearing examiner the question of whether Allegheny Power's failure to file a FERC reactive power tariff for output from the Warrior Run plant in time to be effective on January 1, 2008, violated its duty under a restructuring settlement to maximize the plant's proceeds, after the Commission determined that it lacked sufficient information to rule on the issue (Only in Matters, 3/5/09).

Prior to restructuring, Allegheny entered into a long-term QF contract with the Warrior Run plant. After restructuring, Allegheny sold its entitlements under the contract through competitive bidding, but the sale price was typically below the cost to Allegheny under the long-term contract, requiring a nonbypassable surcharge to recover the difference.

In November 2007, the PSC authorized Allegheny to sell the plant's output into the PJM markets starting in 2008, rather than bilaterally through an RFP, to obtain a more favorable price. In December 2007, the Commission directed Allegheny to file a FERC tariff for reactive power compensation from the plant, which Allegheny did in May 2008, with the tariff effective July 1, 2008.

As only reported in *Matters*, Staff questioned why the tariff was not filed on January 1, 2008, coincident with the sale of the plant's energy into the wholesale market, and questioned whether the failure to file a timely FERC reactive power tariff constituted a violation of Allegheny's duty to maximize revenue from the Warrior Run plant. Staff speculated that Allegheny's delay in filing the tariff may have benefited its competitive generation affiliate.

The Commission noted that Allegheny Power would have received additional revenue in the amount of $358,000 had the reactive power tariff been effective January 1, 2008.

Allegheny responded that reactive power tariffs are complex, and said that it started work on the tariff upon receiving approval to sell the plant's output in the PJM markets in November 2007. Allegheny noted that its diligent and deliberate filing resulted in FERC approving revenues that were higher than what PSC Staff had expected. Allegheny said that the expense and time of composing the filing would have been imprudent prior to the PSC approving the market sale of ancillary services in November 2007. Finally, Allegheny noted that the timing of the Warrior Run reactive power tariff would have had no impact on the tariffs and revenues received by other plants.

While the PSC said it lacked sufficient evidence to rule on the question of whether the five-month delay in filing the tariff constituted a violation of Allegheny's obligation, the Commission did rule that Allegheny did fulfill its obligations to maximize revenues from the plant under the old method of selling the output bilaterally. During the case, there was a question of whether ancillary services were included in the bilateral power purchase agreements, and whether revenues had been maximized. The PSC concluded that, under the agreements, Allegheny sold all of its Warrior Run rights, including any ancillary services.

Texas Public Policy Foundation Opposes Expanded Disconnection Protections

The Texas Public Policy Foundation said that current disconnection and deferred payment rules are adequate for the ERCOT market, cautioning in comments to the PUCT that additional measures, such as those proposed in legislation this spring, or petitions by consumer advocates, could increase costs for other customers by increasing bad debt absorbed by REPs (36131, Only in Matters, 9/18/09).

The Texas Public Policy Foundation noted that current regulations already prohibit disconnection for non-payment if a household member would become seriously ill as a result of that disconnection, and during extreme weather emergencies.

Proposals for expanded protections, "would shift the purpose behind stopping disconnections from weather or danger simply to income," the Foundation said, forcing retail electric providers, "to take on millions of dollars in bad debts resulting from nonpayment-debts that in many cases would be passed on to other electricity consumers in the form of higher rates."

The Foundation further argued that extended periods for deferred payment plans would result in higher arrearages for customers. In the event of a customer default, a greater burden would be placed on, "electricity customers who paid their bills throughout the summer as providers raised rates to cover defaults," the Foundation said.

The Foundation also supported a hard disconnect policy, noting its use in areas not subject to PUCT retail jurisdiction, such as municipals and cooperatives.

"Allowing for hard disconnects lowers the overhead costs of offering electricity to consumers by minimizing the need of REPs and other providers to resort to debt collection agencies, small claims court, etc. ... Consequently, prices across the market will be lowered as REPs are able to more effectively cover their costs. As prices are lowered, more consumers will be able pay their bills without resorting to deferred payments and other payment assistance programs," the Foundation said.

The Foundation noted that during the 2006 disconnection moratorium, six REPs took on an initial $16 million worth of customer debt. Following the moratorium, about half of defaulting customers switched to new providers or were disconnected for failure to repay. The average outstanding balance for these delinquent customers was $785, the Foundation said

"Encumbering REPs with this kind of debt burden threatens to decrease competition in the electric market by destabilizing smaller retailers," the Foundation added.

Brattle Says Energy-Only Markets Not Proven to Assure Resource Adequacy Even as Md., Conn. (Not Texas) Contract for Capacity

Parroting generators' "concerns" regarding ERCOT's energy-only market and raising the specter of political backlash against scarcity price spikes, a report from the Brattle Group claimed energy-only markets, including ERCOT, "have not yet shown that they will be able to attract and retain the generating resources needed to ensure long-term system reliability," despite the robust reserve margins and relatively higher levels of investment that can be found in ERCOT versus eastern RTOs with centralized capacity markets which have failed to attract significant new-build generation.

Brattle's report, prepared for PJM's Capacity Market Evolution Committee, examined various forms of assuring resource adequacy across national and international power markets. However, when it came to ERCOT, Brattle's 90-page report devoted little time to actual market results or detailing the steel in the ground, and instead raised various theoretical challenges, which Brattle said make much-criticized eastern capacity markets superior to ERCOT's energy-only design.

Central to Brattle's conclusion that ERCOT's design has not proven that it can assure resource adequacy are "concerns" raised by "industry participants" cited in the trade press. Such participants, according to Brattle, claim that ERCOT's "optimistic" forecast of reserve margins, "consider neither that many of the older coal-fired power plants will likely retire nor that many of the currently planned generation additions may not be realized due to financing problems." These concerns have been loudest from generators, who would be the largest beneficiaries of adding a capacity payment to the price of generation in the ERCOT market (See Matters, 10/8/09).

Without elaborating, Brattle cites "reliability challenges during the summer of 2009" in ERCOT (though none of these "challenges" translated into late-stage emergency conditions), as well as, "alarming forecasts of inadequate reserve margins only two years ago."

"In addition to current economic conditions, financing new generating capacity has become more difficult due to a significant reduction in current and projected energy prices caused in part by the massive construction of wind power plants," Brattle claims.

To address these resource adequacy questions and uncertainties, including the need for additional regulation capacity to balance wind generation, ERCOT has reactivated its generation adequacy task force, Brattle noted

In spite of its conclusion that energy-only markets have not been proven to assure resource adequacy, Brattle does concede that in energy-only Alberta, "market prices appear to be high enough to support new entry for a variety of generation technologies." Annual net revenues as a percentage of total capital costs are reported to range from 11 to 20 percent for various baseload generation resources, Brattle said, leading the Alberta Market Surveillance Administrator to conclude that the investment climate was attractive.

Brattle faults the energy-only market because, "reliance on market forces [rather than administrative capacity payments], however, also creates considerable risk and public policy concerns related to the question whether the market design will indeed be able to provide for adequate (i.e., publicly and politically acceptable) levels of reliability."

Among other reasons, "long-term resource adequacy may not be achievable in fully restructured energy-only markets due to factors such as mitigation of necessary price spikes," Brattle said.

The volatility required to attract investment in an energy-only design, "comes at a cost - both political and financial," Brattle said. "Politically, the price spikes of energy-only market [sic] are difficult to accept and explain to the public, and even in the absence of apparent market power abuses this can lead policy-markers to impose out-of-market solutions."

However, while Brattle devotes several pages to this risk of the energy-only approach, Brattle concedes (but buries) the fact that capacity markets are also politically uncertain. Listed in a chart on page 72 of the 90 page report (but on the last page before the conclusions and lengthy endnotes), Brattle admits that capacity markets can, "[c]reate political backlash because clearly visible capacity prices draw attention to the high cost of ensuring reliability at current target reserve margins; [and because the] locked-in forward commitment could appear [as an] unnecessarily high cost after [a] change in market conditions reduces resource needs."

Given this, albeit brief, acknowledgement of the uncertainty facing investors in capacity markets, Brattle does not show how such markets are superior in easing investor fears than energy-only markets.

Indeed, while the restructured Texas market attracts considerable legislative attention every session, and certain groups maintain opposition to certain wholesale market elements even out of session (Cities Aggregation Power Project, for example), Brattle does not devote one sentence to the extra-market interventions that have *actually occurred* in markets with forward, centralized capacity markets, such as Connecticut and Maryland.

Connecticut has signed long-term contracts to spur construction of hundreds of megawatts of generating capacity, while Maryland has already signed ratepayer-backed contracts with demand capacity resources due to regulator dissatisfaction with a lack of new supply incented by PJM's capacity market. Maryland regulators have also invited proposals for long-term contracts to support the building of new generation in the state (or proposals for utility self-built generation) in part, because, certain generators have flatly stated that PJM's capacity market will not support new generation in Maryland (i.e., CPV, NRG).

More specifically, the Maryland PSC concluded, in Case 9149, that, "For reasons that are, perhaps, open to debate, the market structures designed to incent new generation in the constrained portions of the State have not yielded any new generation that could narrow or close the 2011-12 gap."

"If nothing else, we know from this testimony (and the list of pending CPCN applications and certificated projects not yet under construction) that we cannot expect market forces to give rise to new generation that will appear in time to solve our reliability problems," the Maryland PSC added.

Whether capacity markets are effective or ineffective may be debatable, but what isn't debatable is that the regulators charged with keeping Maryland's lights on have concluded that PJM's capacity market failed to attract new generation to meet a (then forecast) 2011-12 need, and resorted to an out-of-market solution. No such backstop procurement of new resources has occurred in the ERCOT energy-only market (Brattle notes there are remaining reliability must-run contracts), yet Brattle brazenly concludes it is that the ERCOT market, not PJM, which has failed to prove it can assure resource adequacy.

Focusing just on Maryland ignores, of course, the fierce opposition to capacity markets across consumer groups, certain politicians, and even individual state regulators in eastern RTOs. Accordingly, it seems strained, at best, to cite *potential* political backlash as evidence that the ERCOT energy-only market *may* not provide adequate generation due to intervention, when two capacity market states have already concluded, by conducting out-of-market resource procurements, that capacity markets have failed to assure adequate generation.

Brattle also recommends the introduction of scarcity pricing as an additional feature to address resource adequacy even in markets with forward capacity markets. Given that scarcity pricing would expose ratepayers in these markets to similar price spikes (perhaps less frequently) as under the energy-only approach, Brattle's criticism of the energy-only market as politically untenable due to price spikes would ostensibly apply to capacity markets with scarcity pricing as well, essentially negating about half of Brattle's criticisms of the energy-only approach.

Brattle also repeats the findings of the ERCOT Independent Market Monitor that ERCOT's energy-only market has not worked as designed because small suppliers are not reliably bidding scarcity prices even under scarcity conditions, a concern previously reported (Matters, 8/13/09).

Briefly:

TNMP Limits Meter Tampering Back-Billing

Implementing a request from the PUCT (Only in Matters, 10/16/09), Texas New-Mexico Power said it is limiting back-billing for meter tampering effective Monday Oct. 12, 2009 to a period of not more than 12 months. As in the past, TNMP will limit back-billing to the current REP of record or the previous REP only if the current REP of Record has been the REP for less than 30 days. This interim limit of back-billing will apply to meter tampering only and will not apply to service by-pass (service diversion).

North American Power and Gas Seeks Conn. License

Start-up North American Power and Gas LLC applied for a Connecticut electric supplier license to serve all classes of customers, but said it will focus on the residential market in its first 12 months. North American Power and Gas, which will offer a monthly variable product as its standard contract, said that it expects to enroll 5,000 residential customers in its first year, projecting load at 5 MW. North American Power and Gas is led by President Kerry Breitbart, former CEO of United Companies, where he specialized in commodity trading, particularly oil, electricity, natural gas, and emissions credits. Carey Turnbull, founding partner of Amerex, will serve as chairman of North American Power and Gas. North American Power and Gas has raised $500,000 in capital to begin operations, and had selected Energy Services Group as a vendor for load forecasting, scheduling, settlement, and EDI services.

Md. PSC Schedules Hearing on LDC POR/Proration Compliance Filings

The Maryland PSC will hold a hearing on December 8 on the compliance filings of the gas LDCs to implement various provisions of COMAR 20.59 (RM 35). As only reported in

Matters, Baltimore Gas & Electric and Columbia Gas have applied to institute a Purchase of Receivables program under COMAR 20.59, while Washington Gas Light filed to prorate partial payments between supply and delivery charges (Only in Matters, 10/9/09). The Commission is also accepting comments on the compliance plans by December 1.

Major Energy Services Receives Ohio Gas License

Major Energy Services was awarded an Ohio natural gas license as a marketer, broker and aggregator, to serve all classes of customers at Columbia Gas and Dominion East Ohio (Only in Matters, 9/14/09).

America Approved Seeks Maine License, Amends Md. Application

America Approved Energy Services applied for a Maine electric aggregator/broker license to serve medium and large non-residential customers at Central Maine Power and Bangor Hydro-Electric. America Approved also filed supplemental information with the Maryland PSC regarding its pending application for an electric broker license to serve non-residential customers at the four investor-owned utilities. America Approved reported that it engaged in brokering activity prior to licensing, receiving approximately $2,300 from Maryland operations, which it has since suspended pending licensing.

ISO-NE Sees Adequate Supplies Through 2018

ISO New England reported that it expects to have adequate resources through 2018, assuming all capacity which cleared the Forward Capacity Auction will be in commercial operation by 2011/2012 and continue through 2018/2019, and no generation or demand resources retire or permanently delist. The findings came in ISO-NE's 2009 Regional System Plan. However, the plan reports that the bulk of new generation capacity investment under the Forward Capacity Market has been located in Connecticut, which ISO-NE noted, "has issued several RFPs providing financial incentives for the development of capacity and peaking resources in the state, which requires these resources to participate in the New England wholesale electricity market." The participation of these resources, which are subject to various ratepayer-backed contracts, "has contributed to the large amount of generating resources clearing in the FCM in Connecticut," ISO-NE said. Of the 1,157 MW of new generation capacity procured in the second Forward Capacity Auction (for the 2011/2012 period), the vast majority (1,008 MW) was procured in Connecticut. ISO-NE's 2009 planning report confirms that the region will continue to depend on natural gas for over 40% of its electric energy for the foreseeable future, with gas likely remaining the dominant fuel for setting marginal electric energy prices.

Mpower to Relinquish Texas License

Mpower Retail Energy LP filed at the PUCT to relinquish its REP certificate, stating that it no longer serves customers.

ALJ Denies Dominion Peoples-SteelRiver Settlement

A settlement among several parties that would have approved the sale of Dominion's Peoples Natural Gas Pennsylvania LDC to SteelRiver Infrastructure Fund North America was denied in an interim order by an ALJ, who agreed with PUC Trial Staff that deficiencies in the settlement preclude a determination that the stipulation will result in affirmative, substantial public benefits. The ALJ ordered a prehearing conference to reset the case's procedural schedule. The settlement had been supported by the Office of Consumer Advocate and Office of Small Business Advocate. As only reported in *Matters*, the settlement would have required Peoples Natural Gas to convene a collaborative to develop a strategy to promote retail gas competition within 12 months of the close of the transaction, with participation by retail suppliers, OCA, OSBA and OTS (Only in Matters, 9/7/09). Uncertainty regarding future ownership has also prompted Peoples not to file a voluntary POR plan, though it said it is open to examining a POR plan once its ownership is certain.

Dominion Retail Informs PUCO of Added Trade Name

Dominion Retail, which informed the Pennsylvania PUC that it may elect to market under the newly registered name Dominion Energy Solutions, informed the Public Utilities Commission of Ohio that it may elect to use that new trade name in Ohio as well (Only in Matters, 10/14/09).

FERC Requests Additional Info From New Brunswick Generation on Market Power Study

FERC directed New Brunswick Power Generation Corporation to file additional information supporting its market power study which New Brunswick Generation says shows it does not possess market power in the New Brunswick System Operator balancing authority area (Matters, 9/10/09). Aside from various workpapers, FERC requested additional information regarding the Simultaneous Transmission Import Limit (SIL) study used by New Brunswick Generation, which determines how much imported capacity is available to compete with New Brunswick Generation. Integrys Energy Services has said that New Brunswick Generation has overestimated the amount of import capacity to the relevant market. FERC also requested an update on a review, undertaken by the New Brunswick System Operator, of New Brunswick Generation's OATT, regarding compliance with the requirements of Order No. 890 in the context of reciprocity tariffs filed by a Canadian transmission owner.

Conn. RPS

	RPS Compliance for 2007			
	Class I	Class II	Class III	
Company	3.50%	3%	1%	ACP
CL&P	3.516%	5.464%	1.122%	$0
UI	3.500%	3.000%	0.997%	$3,534
ConEdison Solutions	3.494%	6.717%	2.499%	$3,135
Constellation NewEnergy	3.519%	3.016%	1.008%	
Direct Energy Services	3.189%	2.551%	0.867%	$36,004
Dominion Retail, Inc.	3.504%	3.395%	1.019%	
Gexa Energy Connecticut	0.000%	0.000%	0.000%	n/a
Glacial Energy Inc.	0.000%	0.000%	0.000%	$133,173
Hess Corporation	3.498%	2.999%	0.999%	$1,389
Integrys Energy Services, Inc.	3.488%	3.026%	0.986%	$2,883
MX Energy	3.455%	3.040%	1.002%	$385
Select Energy, Inc.	0.000%	0.000%	0.000%	$9,850
Sempra Energy Solutions	3.561%	3.019%	0.968%	$7,006
Strategic Energy (Direct)	3.555%	3.047%	1.015%	
Suez Energy Resources	2.682%	8.942%	0.805%	$28,514
TransCanada Power Marketing	3.500%	3.005%	0.719%	$121,272
Totals:				$347,145

Conn. ... *from 1*

their RPS compliance fully with RECs. Eleven of the remaining LSEs are subject to some amount of alternative compliance payment (see chart). Gexa Energy, the one remaining supplier, was judged to have served such a small amount of load in 2007 that it was not subject to the RPS.

The aggregate alternative compliance payment (ACP) assessed for 2007 is $347,000, or 10% of the $3.49 million total for 2006. "This dramatic decrease in ACP perhaps indicates that REC prices were generally lower than the ACP amount of $55/MWh for Class I and II and $31/MWh for Class III, and that Companies were more inclined to buy RECs than to pay the ACPs," the draft suggests.

Additionally, the draft would require suppliers to, in future reports, provide information relating to their REC deficiencies and reasons for use of the compliance payment, in order for the DPUC to better analyze REC market conditions and monitor the success of the Connecticut RPS.

The draft found that, in the aggregate for 2007, the Class I standard was met, and that the Class II standard was well exceeded. Additionally, the Class III standard was met exactly at 1% in the first year. "Overall, REC procurements are keeping pace with the increasing RPS mandates. This provides a clear indication that supply is meeting demand," the draft says, which is consistent with the DPUC's findings in its integrated resource plans that long-term contracts with utilities are not required to spur REC development at this time.

The draft further says that Class III RECs were in an oversupply position in 2007, and that there is evidence that this oversupply trend continued in 2008 and 2009 and will continue in the foreseeable future. "This oversupply of Class III source may even be further increased with Connecticut's pending regulations that will allow the banking of RECs," the draft observed.

The draft would rule that CL&P's transfer of 161 Class III RECs from the Conservation and Load Management Fund to meet its own RPS obligations was inappropriate, finding that CL&P must compensate the C&LM Fund for the RECs. CL&P had argued that the RECs would have expired if it had not transferred them, as CL&P said that there were no third-party offers to purchase the RECs.

"These RECs belonged to the C&LM Fund, not to CL&P, and to the extent CL&P needed Class III RECs to satisfy its own RPS requirements, CL&P should have treated itself as a third party. CL&P's need for these 161 RECs was indeed a 'viable opportunity to sell' for the Fund. CL&P surely would have refused any electric supplier's request for free RECs from the C&LM Fund if such supplier reasoned that the RECs would have gone 'unused' if they were not given away," the draft concludes.

The draft would require CL&P to pay a total of $9,683 for the transferred RECs, representing the costs of the Class III RECs at the average sales price of $25.93, plus interest, plus the amount of the compliance payment CL&P would have been subject to absent the transfer.

The draft said that two suppliers that served load did not file the required annual RPS compliance reports. The body of the draft identified Gexa as one of the two companies, but a legend to a chart indicated Gexa did file with the DPUC on October 10, 2008. Upon reviewing the docket, Gexa did file a statement regarding its 2007 operations on that date in docket 08-09-15, prior to the October 15 deadline. Regardless, the DPUC put suppliers on notice that failure to file the annual RPS compliance reports, "will adversely affect [their] electric supplier license."

West Penn Power ... from 1

contracts it won in the auction will result in an increased energy margin of approximately $10 per MWh (pre-tax) for 2011 compared to 2010. Available for bid were one 17-month residential contract, one 29-month residential contract, and three 17-month non-residential contracts.

See the chart to the right for a pricing breakdown.

Allegheny Pricing Breakdown:

	Residential	Small/Medium Non-Residential
Average weighted retail generation price ($ per MWh; estimates)	$65.29	$67.24
Amounts included in prices shown above ($ per MWh; estimates):		
Gross receipts taxes and line losses	$8.22	$8.45
Capacity (excludes shaping)	$4.14	$5.37
Energy and all other components	$52.93	$53.42