Energy Choice Matters

October 2, 2008

Non-Investment Grade REPs Would Need $1 Million or More in Liquid Capital for Certification

A PUCT Staff Proposal for Publication would bifurcate financial qualification requirements for REPs under which non-investment grade REPs would be required to show at least $1 million in liquid capital, as Staff acknowledged that some current REPs may be unable to qualify as a REP under Staff's proposed standards (35767, Matters, 8/13/08). REPs would have one year to become compliant with the new rules, which Staff argues are necessary to decrease POLR transitions and the attendant customer harm.

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Md. Utilities' Analyses Show Costs, Risks from Managed Portfolios

"Managed portfolios that incorporate longer term, five years or greater, fixed block contracts are more expensive on an expected value basis and can be more volatile as well," NERA Economic Consulting said in an analysis prepared for Baltimore Gas & Electric and Allegheny Power relating to integrated resource planning (Case 9117, Matters, 7/4/08).

"Were the utilities to enter into five-year and ten-year contracts covering the projected full SOS energy need, customers would expect to pay more and the price paid could be more volatile," NERA added.

A five-year fixed price contract would increase expected SOS per kWh prices by 6.8% for both Allegheny and BGE. A ten-year fixed price contract would increase expected SOS per kWh prices by 14.5% for Allegheny and 12.5% for BGE. Those NERA estimates do not include the costs of imputed debt, which would likely increase not only SOS costs to Maryland customers but also costs to all distribution customers, since the utility weighted average cost of capital would be affected by debt imputation.

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CenterPoint Asks for Disconnect Moratorium Through Oct. 24

CenterPoint Energy asked the PUCT to extend the moratorium on Disconnects for Non-Pay (DNP) until October 24, the date on which CenterPoint expects to be able to resume completing DNPs, it said in a plan to return to normal operations (36150). The emergency moratorium is currently set to expire October 10.

As field personnel complete restoration work, CenterPoint will first assign personnel to clearing a 16-day backlog for Move-ins, Move-outs, and Reconnection requests (encompassing 73,000 backlogged requests). CenterPoint expects to begin clearing this backlog the week of October 6. The TDU will treat all requests as standard requests and will not charge for or provide priority status to any requests. CenterPoint expects being able to execute new Move-ins, Move-outs, and Reconnections during the week of October 24, with priority status being accepted starting November 6.

CenterPoint reported an 11-day backlog for DNP requests, and expects to start executing DNPs the week of October 24.

Other services, such as out-of-cycle meter reads and meter re-reads, will be offered starting the

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PJM Requests to Use Three Pivotal Supplier Test in Regulation Market

PJM has requested FERC approval to apply a three pivotal supplier test to the regulation market starting Dec. 1.

A stakeholder group fashioned compromise rules meant to deter market power while not further discouraging already low participation in the regulation market. PJM's proposal would replace the current mitigation of cost-based offers from the two dominant companies (Dominion and AEP) at all times with a real-time mitigation approach that:

(i) encompasses use of the three-pivotal supplier test as the screen for market power;

(ii) defines available supply for purposes of the market structure screen as all offers submitted at a total price (offer plus opportunity cost) less than or equal to 150% of the cost-based clearing price;

(iii) provides for an adder of $12.00 to the calculation of mitigated cost-based offers;

(iv) eliminates the current practice of netting regulation market revenues against balancing operating reserve payments; and

(v) redefines opportunity costs to measure those against the cost-based offer for the unit, rather than against the market-based offer.

The current $100/MWh price cap would remain. The $12 adder, opportunity cost revisions, and elimination of netting of regulation revenues against balancing operating reserve payments are meant to address concerns that sellers are offering less than half of their regulation capability in the market, and that offer-capped sellers offer even less.

PJM estimates that parties controlling units with regulation capability offered only 30-40% of that capability into the market in 2007. Offer-capped sellers offered even less - only 15-30% of their capability.

The regulation ancillary service is a critical reliability tool needed to maintain stable system frequency and control, PJM reminded FERC, and institution of market power mitigation in the market without the compromise measures listed above could decrease the incentives for suppliers to offer regulation into the market.

The compromise acknowledges that if FERC, in an ongoing review, determines the three pivotal supplier test to be unjust and unreasonable, all aspects of market power mitigation in the Regulation Market will need to be revisited.

REPs Challenge Non-Volunteer POLR Designations

Several REPs challenged the PUCT's designation of the REPs as Non-Volunteer POLRs for certain customer classes (Matters, 9/26/08).

Suez Energy Resources NA objected to its selection as a Non-Volunteer POLR for large non-residential customers in the joint AEP Central/Sharyland territory because it is not a registered provider in Sharyland and does not have the required third party supplier agreements or EDI certification in place. Further, because Suez Energy Resources is not a registered supplier in this territory, its internal system configurations cannot support providing electric service to customers in the territory.

Suez Energy Resources only serves commercial and industrial customers, and Sharyland is primarily a residential development with very minimal commercial development, Suez noted. "This minimal commercial load potential does not overcome the cost of market entry for Suez Energy Resources, which is why we aren't active in that utility area today. The considerable costs to enter into the necessary supplier agreements, post the required credit support, obtain EDI certification, and setup our internal system configuration to resolve system limitations to serve the Sharyland territory substantially outweigh the minimal market viability and commercial potential," Suez said.

Reliant Energy Solutions, Reliant's REP for large C&Is, objected to its selection as the Non-Volunteer POLR provider for the small non-residential customer class in all areas. Reliant Energy Solutions said it does not serve small non-residential customers as defined in P.U.C. SUBST. R. 25.43(c)(11) except for the low-usage sites of its large non-residential customers, or commonly-owned or franchised affiliates of its large non-residential customers, and is thus exempted from designation as a Non-Volunteer POLR for the class.

Constellation NewEnergy challenged its

designation as Non-Volunteer POLR for Small Non-Residential Customers in the AEP Texas North and AEP Central/Sharyland service areas.

Briefly:

Catalyst Files for Bankruptcy

The Georgia PSC issued an emergency Rule Nisi (show cause order) to natural gas marketer Catalyst Energy which has filed for bankruptcy protection after losing a credit and gas supply agreement with Constellation Energy (Matters, 10/1/08). The PSC will consider Catalyst's ongoing certification at a hearing on Friday, to determine whether customers should be reassigned to other marketers. Catalyst has been unable to secure alternative credit, blaming illiquid capital markets. Catalyst Energy has 30,000 customers in Georgia and $20 million in liabilities. It is also certified as a REP in Texas.

Bridgeport Energy II Withdraws Peaking Project, GenConn to Fill Gap

Bridgeport Energy II, a joint venture of Dynegy and LS Power, has informed the Connecticut DPUC that it wishes to withdraw its Contract for Differences with United Illuminating to build cost-of-service peaking generation. Bridgeport Energy II asked the DPUC to confirm that the CfD is null and void and that its security be returned. Bridgeport Energy II made the decision because the DPUC refused to modify the CfD based on the possibility Bridgeport Energy II may not clear the first Forward Capacity Auction for which it is eligible, as contractually required to do, because of an error in making its capacity auction election (Matters, 9/29/08). Bridgeport Energy II indicated that should FERC accept the generator's waiver request to amend its capacity auction election, Bridgeport Energy II may inform the DPUC it is willing to accept the current CfD. However, the DPUC said it intends to approve the GenConn's 200 MW Middletown CfD by October 6 as a replacement if Bridgeport Energy II withdraws it CfD. GenConn is a joint venture between NRG Energy and United Illuminating.

Grid to Pay Constellation $50 Million in R.I. Contract Settlement

National Grid will pay Constellation Energy $50.2 million to resolve outstanding disputes over fuel costs from supply contracts and capacity payments related to Grid's Rhode Island electric distribution utility. The Rhode Island PUC approved the settlement, which Grid considered preferable to a court fight which could expose Grid to $300 million in liabilities. The payment resolves disputes from long-term supply contracts Grid had entered into with CEG in 1998 that last through 2009. Grid believed that a fuel adjustment factor under the contracts expired in 2004, but CEG disagreed and filed suit to collect post 2004 costs. A court ruled against Grid in a similar fuel-cost case with TransCanada. CEG supplies about 66% of Grid's power and said that the fuel adder costs from 2005 through 2009 amount to $189.4 million. Also disputed were capacity payments under the contract given the ISO's transition to a Forward Capacity Market. CEG claimed Grid owed $178.3 million for such capacity payments.

FT: EDF Preparing Another Constellation Offer

EDF is preparing to mount another attempt to wrestle Constellation Energy away from MidAmerican Energy Holdings as it nears a pact with private equity group KKR, London's *Financial Times* reported today. EDF CEO Pierre Gadonneix is to meet with KKR executives this week to complete an offer meant to grow EDF's U.S. presence and take advantage of renewed interest in nuclear construction, the *Times* said. MidAmerican said it has completed its due diligence review of CEG's retail and wholesale businesses and will proceed with the acquisition, waiving the due diligence related termination right.

PUCT Grants Two REP Certificates for Energy Services Group

The PUCT granted REP certificates for TexRep3 (Shogun Power) and TexRep4 (Busheido Energy). Both are affiliates of Energy Services Group (Matters, 8/29/08).

DPUC Sets Hearing on MXenergy Complaints

The Connecticut DPUC has set a hearing on its investigation of customer complaints against MXenergy for Nov. 10 (Matters, 8/27/08).

Grid Filing Plan to Own Solar in Massachusetts

National Grid is expected to file a proposal to install 5 MW of solar capacity on utility-owned properties with the Massachusetts DPU today. Grid also wants to lease rooftop space from large C&I customers, and eventually aid residential customers in installing and maintaining solar systems.

REP Certification ... *from 1*

Under Staff's proposal as filed with central records, REPs could meet financial standards through two processes. "Tier 1" REPs, or their guarantor, must demonstrate and maintain:

(i) an investment-grade credit rating; or

(ii) tangible net worth greater than or equal to $100 million, a minimum current ratio (current assets divided by current liabilities) of 1.0, and a debt to total capitalization ratio not greater than 0.60.

"Tier 2" REPs or their guarantor must demonstrate and maintain:

(i) liquid capital not less than $3 million;

(ii) liquid capital not less than $2 million, provided that the REP has continuously served retail customers in the Texas retail market without sanction or default for at least two years; or

(iii) liquid capital not less than $1 million, provided that the REP has continuously served retail customers in the Texas retail market without sanction or default for at least three years.

Current REPs that cannot meet the criteria within six months would have to notify the Commission, and would then have to cease operations within 12 months of the rule's effective date.

Tier 1 REPs would have to keep customer deposits in a restricted cash account or an escrow account, or provide an irrevocable stand-by letter of credit in an amount sufficient to cover 100% of customer deposits and advance payments. Tier 2 REPs would not have the option of using a restricted cash account, and could only hold deposits and advance payments in an escrow account, or use an irrevocable stand-by letter of credit.

TDUs could not impose deposit requirements on Tier 1 REPs, except for amounts related to the payment of transition charges.

However, TDUs shall require Tier 2 REPs to provide security for payments of amounts billed. The size of the deposit, type of security, and other factors shall be prescribed by the TDU's tariff for retail delivery service.

A TDU may create a regulatory asset for bad debt expenses, net of collateral posted by a REP, resulting from a REP's default on its obligation to pay delivery charges to the TDU. The provision does not imply or guarantee the recovery of the regulatory asset in a rate proceeding.

Revamped technical qualification requirements would mandate that REPs have principals or permanent employees in managerial positions whose combined experience in the competitive retail electric industry or competitive retail gas industry equals or exceeds 15 years. An individual that was a principal of a REP that experienced a default shall not be considered for purposes of satisfying the experience provision.

REPs would need to have at least one principal or permanent employee who has five years of experience in commodity risk management of a "substantial energy portfolio." Alternatively, a REP may provide documentation demonstrating that the REP has entered into a contract for a term not less than two years with a provider of commodity risk management services that has been providing such services for a substantial energy portfolio for at least five years. A substantial energy portfolio is defined as managing electricity or gas market risks with a minimum value of at least $100,000.

Staff's proposal strikes current Subst. R. §25.107(c)(4), which allows REP applicants to identify certain information or documents that applicants believe to contain proprietary or confidential information. New subsection §25.107(i)(11) states that all applications and reports under the subsection shall be filed with the Commission's Filing Clerk in accordance with the Commission's Procedural Rules Chapter 22, Subchapter E (relating to pleadings and other documents). Subchapter E §22.71 generally prescribes rules for confidential treatment in all procedural cases.

The proposal states that Option 2 REPs (who may only contract with customers 1 MW or larger) cannot aggregate customers to meet the 1-MW threshold.

Md. IRPs ... *from 1*

Given the size of BGE's Residential and Type I Commercial load, covering the projected full SOS energy need on a long-term basis could trigger as much as $1.3 billion to $2.2 billion of imputed debt. For Allegheny, the level of imputed debt is estimated to be in the range of $330 million to $560 million, NERA reported.

The impact of customer choice and migration is a primary reason that long-term contracts can be both more expensive and more volatile on an expected basis. "Longer term fixed-price purchases are not a reasonable alternative in a customer choice environment and would threaten the viability of customer choice," NERA said, pointing to California's experience with above-market, long-term contracts which became a "source of considerable regret," and required the suspension of direct access.

Under base case assumptions, ownership by BGE of a 600-megawatt combined cycle plant put into service in 2014 would raise the net present value of SOS portfolio costs by $128 million during the planning period. Similarly, the ownership by Allegheny of 100 megawatts of wind generation capacity put into service in 2011 would raise SOS portfolio costs for Residential and Type I Commercial customers during the planning period by a net present value of over $80 million. While significant benefits may accrue after the planning period, the impacts during the planning period are negative in all cases considered, NERA said.

NERA Monte Carlo simulations coupled with qualitative risk assessment indicate that actively managed portfolios of contracts up to two years in duration are not in the customers' best interest as compared to buying full-requirements service under two-year contracts. According to NERA modeling, a managed portfolio implemented with two-year contracts would provide a small expected costs disadvantage relative to full requirements purchases and no difference in volatility. A managed portfolio using a combination of two-year, one-year and monthly purchases and a limited amount of spot purchases would at best achieve a 1-3% reduction in expected costs for customers, but that small possible savings would come at the expense of more price volatility and taking on more risk.

NERA noted that its model does not capture all of the risks that would remain with customers in a managed portfolio, and therefore understates the risk advantage (i.e., price protection) provided by full requirements and overstates the apparent, minimal cost advantage of the managed portfolio. Under a managed portfolio approach, the market and regulatory risks faced by the full-requirements supplier are not eliminated, but are merely shifted to the utility and ultimately to the SOS customers. Leaving such market risks unhedged or uninsured may reduce cost in the short-run, but would ultimately result in higher prices if the risks materialize, NERA said.

NERA's market model indicates that between now and 2023, two new combined cycle units should be added in the Southwest Mid-Atlantic Area Council region of PJM, and that price signals, "should be sufficient to induce merchant entry of those two units."

Ownership of these new units by utilities as opposed to merchants would include costs and risks. Merchants have demonstrated the ability to operate at lower heat rates and greater availability. Merchants would bear the risk of construction costs overruns, while utilities would pass on prudent cost overruns, NERA noted. "With commodity prices and construction costs escalating such overruns could well occur," NERA said.

An analysis by the Pepco Holdings' utilities also showed that the current full requirements RFP procurement process best manages the statutory mandate to balance least cost with least volatility, though Pepco favors expanding the RFP ladder to three years instead of the current two.

Should the Commission mandate a managed portfolio, Pepco urged that a blended portfolio which includes some RFP procurements be used to decrease price volatility and risk. If any managed portfolio is used, Pepco urged either limits on customer migration, or the triggering of a nonbypassable surcharge if migration is expected to increase SOS rates by at least 5%, to protect remaining SOS customers from paying higher rates due to load migration.

CenterPoint ... from 1

week of Nov. 6, dependent on completion of the backlogs listed above. CenterPoint anticipates beginning the normal meter reading routes no earlier than October 13, 2008.

Beginning the week of October 6, 2008, CenterPoint Energy will utilize meter readers to "sweep" the coastal areas to document premises that will no longer be capable of taking electric power. CenterPoint will send "suspension of service" transactions to the REPs when a location is determined to not be capable of taking service. The REPs will then need to send Move-out requests to ERCOT. The Move-out will be processed through ERCOT and CenterPoint will provide a disconnection as of September 12, 2008, and an estimated usage for the time period prior to the storm. The transactions will remove the REP of record and retire the ESI ID for the premise. If the premise is able to take electric power in the future, the customer would need to obtain a REP and new ESI ID.

Also, beginning the week of October 6, 2008, CenterPoint will determine premises that are unable to take service on a temporary basis. These premises will have services temporarily suspended, so that usage for the addresses will not be submitted to ERCOT and CenterPoint's charges will not be billed. Once the customer is capable of resuming electric service, the customer will need to request a new meter and that service be restored. At that time, CenterPoint will install a meter and resume providing service to the customer.

CenterPoint asked the PUCT to suspend the requirement to perform "smoothing" of meter read estimates (to account for over/under estimations) until January 1, 2009, stating that the smoothing process would negate actions CenterPoint has taken to reflect lower than normal usage due to outages in current estimates. Smoothing would also require rebilling and create customer confusion, CenterPoint said, and would also negatively impact wholesale settlement.

CenterPoint has trimmed outages to 4,605 customers.

ERCOT also announced that it will be temporarily extending cancellation timing for a subset of enrollment orders in the CenterPoint Energy and Texas-New Mexico Power territories, as both TDUs requested that ERCOT help in their efforts to clean up their backlog of transactions.

ERCOT plans to extend the cancellation window to November 10, 2008 for Move-in and Move-out orders to avoid orders being cancelled, with exception due the TDUs' inability to respond within the window. ERCOT will be working with CenterPoint Energy and TNMP to evaluate orders received up to and including October 3, 2008.

The intent is to minimize the number of Move-in or Move-out orders that would cancel due to the timeframe necessary to handle the recovery effort and minimize potential out of synch conditions in the market.