Energy Choice Matters

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NRG Shareholders Reject Exelon's Directors, Exelon Forced to "Move On"

Exelon failed to place any of its nominees on NRG Energy's board at yesterday's annual shareholder meeting, prompting Exelon to withdraw its hostile offer for NRG.

About 66% of NRG's total shareholders voted to reject Exelon's various proposals to expand the board and nominate its slate of directors (or 75% of the 87% of shareholders casting a vote). All of NRG's director nominees were re-elected.

"NRG stockholders understood that this vote was all about value and they voted overwhelmingly to send a message that Exelon's current offer was unfair to NRG stockholders," said NRG CEO David Crane.

Exelon CEO John Rowe said that the company will "move on" after the vote, representing another failed acquisition for Exelon after its proposed merger with PSEG ended with a whimper in 2006 over market power concerns and demands for rate concessions. Exelon was unwilling to raise its offer to a level that would have been acceptable to NRG shareholders.

For NRG, focus will return to a standalone strategy focused on delivering financial results, maintaining substantial liquidity, and returning capital to stockholders. While Crane noted the current climate remains a buyer's market for M&A, he said no deals on the horizon are compelling enough to warrant action.

Crane said that 10 to 15 potential suitors were identified when NRG conducted its market discovery in response to the Exelon offer. Most potential buyers were either large European generators or utilities looking for entry into the U.S. and attracted by NRG's nuclear portfolio, large U.S. utilities, or cash buyers. Crane said that the European suitors were hesitant due uncertainty over carbon legislation, while U.S. utility suitors faced credit and debt challenges. Cash buyers were

Continued P. 4

Direct Energy Says Pa. Choice Statute Allows it to Keep Pike County Aggregation Customers

Pennsylvania's Commonwealth Court has determined that an opt-out procedure satisfies the statutory test for customer choice under the state's Electric Choice act, Direct Energy said in a reply brief arguing against the return of its customers acquired in the Pike County Light & Power aggregation to default service.

The Office of Consumer Advocate and Office of Small Business Advocate have contended that absent an affirmative choice by customers, they should be returned to Pike's default service upon the end of the aggregation in May 2011.

Direct countered, however, that the consolidated statutes referenced by both advocates do not use the terms "affirmative" or "actively" to describe customer choice as the advocates suggest. The statutes merely hold that the "choice" of a provider remains with the customer, and that a customer's provider may not be changed without "consent," Direct noted.

The Commonwealth Court, Direct said, has ruled that an opt-out procedure, Direct's suggested mechanism for dealing with customers at the end of the aggregation, complies with the statutory provisions cited by both advocates. A customer's acquiescence to remain with Direct by not taking

Continued P. 5

Md. PSC Denies Inclusion of IRP Costs in Allegheny SOS Filing

The Maryland PSC ruled that Allegheny Power cannot include the costs of a study of integrated resource planning prepared at the request of the Commission under Case 9117 in its Standard Offer Service and Hourly-Priced Large Customer Service costs.

In Case 9117, the Commission directed the utilities to make recommendations for a portfolio mix that, "best balances the competing mandates of Senate Bill 400," which obliges the Commission to explore possible means for obtaining Standard Offer Service through, "a portfolio of electric supply that provides electricity at the lowest cost with the least volatility." Allegheny, with Baltimore Gas & Electric, contracted with NERA Economic Consulting to conduct a study of various long-term procurement scenarios.

Allegheny included the costs of the study in its 2008 Standard Offer Service/Hourly-Priced Large Customer Service actual incremental costs filing.

However, the Commission found that the costs of the NERA services associated with Case 9117 shall not be included in Allegheny's 2008 SOS or hourly priced service actual incremental costs. "After reviewing the Phase I and Phase II Settlement Agreements approved in Case No. 8909, the Commission concluded that costs associated with the mandatory requirement to file an IRP study by Case No. 9117 are not costs incurred in providing service to the Company's Types I and II SOS commercial customers and hourly-priced large customers for the calendar year 2008," the PSC said.

Allegheny was directed to file an amended report in which the NERA costs are removed from the incremental cost of providing default service.

ROS Submits PRR on Wind Resource Frequency Response

ERCOT's Reliability and Operations Subcommittee (ROS) has submitted new Protocol Revision Request 824 to add a requirement for wind generator control systems to be programmed to respond to frequency deviations by controlling Wind-powered Generation Resource (WGR) real power output in a way that is similar to governor response for conventional generators. The PRR will maintain system frequency better with additional wind generation in the ERCOT market, which will allow greater utilization of wind generation, ROS said.

While the PRR would impose additional costs for hardware and software for wind resources as well as some limits on wind generation technology which may be utilized, thus increasing capital costs for wind resources, ROS expects that the change will produce a "significant" reduction in production costs since more wind generation can be allowed on the ERCOT system. The PRR will produce some reduction in individual wind resource output as wind is "spilled" whenever frequency increases above the dead-band.

As wind resources displace more and more conventional generation, there will be a growing need for wind resources to replace the primary frequency response capability not being provided by the Off-line conventional generators, ROS noted. Wind resource primary frequency response will be of particular value if frequency increases occur, ROS added.

The PRR is scheduled for consideration at the August 20, 2009 Protocol Revision Subcommittee meeting.

CAISO Calls Conclusions on Exceptional Dispatch Premature

The California ISO called conclusions on the market impacts of exceptional dispatch "premature" in comments opposing a technical conference of such out-of-market dispatches, even as Calpine said that the repeated use of exceptional dispatch is having the effect of eliminating congestion in a locational price market (EL08-88 et. al.).

NRG Power Marketing, J.P. Morgan Ventures Energy, and the Western Power Trading Forum have petitioned FERC for a technical conference on the frequency of exceptional dispatches in the CAISO market, which the generators said well outpaces stakeholder expectations. A June report showed that CAISO ordered over 1,000 Exceptional Dispatch commitments in the six weeks since the beginning of the Market Redesign and Technology Upgrade market, which generators said is distorting the CAISO market and blunting price signals (Matters, 7/7/09).

However, CAISO said that, "parties to these proceedings should not be surprised by the use of Exceptional Dispatch, particularly in the first few months of the new market design."

"[T]he ISO's operators are still in the process of gaining experience with the market software, and consequently the ISO has had to rely on Exceptional Dispatch during the initial months of operations under the new market to a greater degree than it anticipates will be necessary in future months," CAISO said.

While generators have recommended allowing exceptionally dispatched resources to set the Locational Marginal Price as a remedy to the frequent use of exceptional dispatch, CAISO called any proposed market changes "premature," as the market only has few months of experience with the mechanism, and the CAISO has not had a reasonable opportunity to reduce reliance on exceptional dispatch over time.

CAISO further disputed the notion that any trend is evident in the exceptional dispatches to date. "In fact, over the first two and a half months after market implementation, the frequency of Exceptional Dispatches has fluctuated: the average number of Exceptional Dispatches per day was 18.8 for the April 1-15 time period. This average increased to 27.6 for the April 16-May 15 time period, but decreased to 20.35 for the May 16-June 15 time period. Moreover, the most recent data from June indicates that the capacity obtained through Exceptional Dispatch for that month was half of what it was during May," CAISO reported.

Seasonal requirements could also influence the volume of exceptional dispatch, CAISO said, and thus if a technical conference is convened it should be after the summer period to allow CAISO to obtain data from the peak period and analyze the results. Any conference should be limited to a discussion of the frequency and reasons for exceptional dispatch, and not market changes, CAISO argued.

CAISO also reiterated its position that providing information on individual exceptional dispatches, rather than aggregate data, could facilitate the exercise of market power.

The Sacramento Municipal Utility District lent support to calls for a technical conference, arguing that while CAISO is meeting FERC's directive for a report on the frequency of exceptional dispatches, CAISO has not met the requirement to report on the "causes" of exceptional dispatches.

CAISO said parties must provide evidence, "that consists of more than mere unsubstantiated, speculative allegations," that exceptional dispatch requires modification.

Calpine asserted that, "pricing evidence indicates that Exceptional Dispatch is having the effect of eliminating congestion."

"For example, there have been days in which system load was forecast well in excess of 40,000 MW but, surprisingly, congestion has been absent in virtually all of the day-ahead LMPs. The absence of a single binding transmission constraint on the system when load exceeds 40,000 MW is highly suggestive that the CAISO dispatch of out-of-market resources, presumably to manage reliability, has had the unfortunate consequence of suppressing rational price dispersion - one of the primary goals of locational pricing mechanisms," Calpine said.

"There is substantial basis to infer from the limited market data available that the CAISO's use of Exceptional Dispatch has distorted prices, depriving generators and consumers of competitive market price signals," Calpine added.

"Exceptional Dispatch may have contributed to the otherwise unexpected and unexplained declines in heat rate spreads in the Integrated Forward Market under MRTU. The CAISO's market monitor has reported that, in April, on average, throughout California regions, prices were significantly below competitive benchmarks, indicating negative markups on many days. This is the first time such price inversion has been realized in all zones of the California market consistently over a month long period," Calpine reported.

Calpine noted that while CAISO anticipated that the total number of Exceptional Dispatches would amount to one percent or less of the thousands of automated daily dispatches, the actual use of exceptional dispatch during the first months of MRTU has proven more substantial. For May, the quantity (in MWh) of exceptional dispatches averaged about 2.6% of total load, and ranged as high as 7%, Calpine said.

CAISO had also anticipated that most exceptional dispatches would occur in order to manage energy output in real-time, for reasons akin to the reasons that out-of-sequence dispatches were issued under the old market design, and not for the purpose of committing resources. However, while real-time exceptional dispatches exceed day-ahead dispatches in frequency, the latter are common; moreover, unit commitments to minimum load account for 40% of the frequency of exceptional dispatches and for nearly 90% of the total MWh of exceptional dispatch, Calpine said.

Briefly:

FERC Grants NYISO Waiver Regarding Error with De Minimis Impact

FERC granted the New York ISO a requested waiver to excuse the NYISO from recalculating market clearing prices, revising generator settlements after-the-fact, and revising mitigation results due to a tariff implementation error that had a "de minimis (but perceptible) impact" on mitigation measures (Matters, 6/22/09). A software change in January 2009 resulted in the unanticipated result of NYISO using different start-up bids to commit and settle certain generators from the start-up bids that were used to conduct such generators' bids for mitigation purposes, and to develop bid-based start-up reference levels. The NYISO identified the following de minimis Real-Time Market impacts that resulted from the error: (i) three instances in which generators' guarantee payments were over-mitigated by a total of approximately $265.04, (ii) two instances in which generators' guarantee payments were under-mitigated by a total of approximately $178.95, and (iii) a negligible (0.7%) impact on the development of the only real-time bid-based start-up reference level that was used in the NYISO markets during the affected period. The Day-Ahead Market was not affected.

PECO Launches Second Procurement

PECO has launched its second default service supply solicitation for the period starting January 1, 2011, with qualification materials due on September 1 (http://pecoprocurement.com/). In the current RFP, PECO seeks to purchase full-requirements supply for residential, small commercial and medium commercial customers, as well as baseload block energy.

Calif. PUC Asks for More Info on Vacant CEO Position at PG&E Utility

The California PUC directed PG&E Corp. to provide more information about the appointment of Christopher Johns as utility Pacific Gas & Electric's president, and the decision not to fill the CEO position at the utility, in response to PG&E's motion to withdraw its request for a waiver from various affiliate rules it sought when it planned to have Peter Darbee serve as CEO of both the utility and parent corporation (Matters, 7/6/09). In an assigned commissioner's ruling, Commissioner John Bohn said that the decision not to fill the CEO position at the utility raises the question of whether the required separation of key officers or their functional equivalent at both the utility and holding company will be satisfied. Bohn asked PG&E to explain which corporate officer, either at the holding company or the utility, will perform the "functional equivalent" of the duties of the CEO for the utility company. If no key officer within the PG&E utility organization will perform the "functional equivalent" of the CEO duties for the utility, Bohn asked if those utility CEO duties will be the responsibility of the holding company CEO. If not, how will a vacant utility CEO position comply with affiliate rules which call for separate CEOs among the "key officers" functioning at both the utility and holding company, Bohn asked.

NRG ... from 1

only offering a minimal premium over Exelon's offer that still undervalued NRG, Crane said, reiterating NRG will not revisit any of the offers.

Though momentum had been shifting to NRG since the late spring, Exelon's defeat represents a stunning reversal from its position at the start of the year, when many analysts believed

Exelon would prevail, especially in light of NRG's January announcement that preliminary 2008 earnings were below guidance, which rattled investors, and Exelon's tender offer receiving 51% of shares in February.

Crane credited three events for turning the tide against Exelon's offer:

1. NRG's acquisition of Reliant Energy's ERCOT retail book;

2. Exelon's disclosure in March that it only had 30% of power hedged for 2011 as opposed to the 80% previously believed, which led investors to question Exelon's credibility, and

3. The turnaround in stock prices starting in March which moved NRG shareholders from being risk averse to more confident in long-term value and growth.

Crane said that with the Exelon distraction removed, NRG will likely be able to announce the sale of a 20% stake in the South Texas Project expansion in the third or fourth quarter.

Direct ... from 1

action to choose another provider or return to default service is thus legally a choice to remain with Direct under the Choice Act, and cannot be abrogated by the Commission, Direct said.

Direct noted that the PUC has held such a mechanism to be applicable under PECO's Market Share Threshold, where customers acquired by competitive suppliers through bidding would not be automatically returned to default service upon the expiration of rate caps.

The Office of Small Business Advocate reiterated its view that Direct's five-year relationship with aggregation customers makes it an incumbent, arguing that allowing Direct to keep customers at the end of the aggregation would harm competition.

"Direct's head start would make it difficult for other [suppliers] to compete," OSBA said, noting other suppliers will need to include marketing and acquisition costs in their rates to win load away from Direct; costs which Direct did not incur and thus must not recover through rates.

Sending customers back to Pike's default service would enhance competition and level the playing field, OSBA reasoned.

Direct rebutted that argument, noting that handing back to Pike a monopoly over the customer relationship would hinder competition and discourage new entrants. Direct noted that other suppliers have not intervened in either the instant case or cases involving the extension of the aggregation plan, while all the suppliers competing for the original Pike aggregation agreed that normal contract extension provisions should be used by suppliers at the end of the aggregation term, rather than returning customers to default service.

Regardless, Direct said that, "The Commission is not charged with nor required to ensure that all [suppliers] as to each other have an equal playing field -- the Choice Act leaves that to the competitive market." The Commission is only charged with ensuring that the distribution company does not enjoy a competitive advantage which would impede competition.

"Direct seems to define 'competition' as the percentage of customers taking service from [suppliers] instead of from the [distribution company]," OSBA replied. OSBA said that the same level of migration could be maintained by re-bidding the aggregation pool, which would ensure customers receive a competitive price. Though not rate regulated, Direct's price under the aggregation has either been competitively set through a bidding process, or subject to negotiation under PUC review, OSBA noted, but such checks will not continue once the aggregation ends if Direct is allowed to retain its customers.

Direct argued that it would face a mass exodus of customers if it raised prices above a competitive level, but OSBA said that because of Direct's incumbent status, and the likely dearth of new entrants, competition cannot be relied upon to put the brakes on price increases.

OSBA also said allowing Direct to retain customers on an opt-out basis will likely affect the type of default service procurement Pike undertakes in its next default service plan. If most of the load remains with Direct, Pike will likely be confined to spot purchases for its small default service load. Because Direct may serve customers on a monthly variable rate for its legacy aggregation customers, allowing Direct to retain customers may mean that customers are left with no fixed price options, OSBA reasoned.