Energy Choice Matters

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NRG's Crane Says ERCOT Market Overreacting to CREZ Wind

The market has "overreacted" to the potential prospect of 18 GW of new wind power in ERCOT, NRG Energy CEO David Crane told investors on a conference call yesterday.

Undoubtedly, the prospect of a flood of zero marginal cost wind farms has "significantly" affected the psychology of the ERCOT forward heat rate market, Crane noted, but the ultimate pace of wind additions is less certain.

"In short, when it comes to wind in Texas and its impact on forward heat rates, stay tuned. The market has oversold it and we're due for a reality check," Crane observed.

In addition to the billions needed to build transmission, Crane pointed to the billions needed to maintain the quick-start, gas-fired back-up capacity needed to "firm" the wind. Crane expects ERCOT to consider in the "very near future" the issue of ancillary services; what wind-firming capacity is needed; and how, and who, will pay for such capacity and ancillary services.

Crane again compared wind's impact on forward heat rates to the market's reaction to TXU's since-scuttled plans to bring 11 coal plants online by 2012, noting that forward heat rates in Texas "rebounded nicely" when it became apparent TXU was not going to add anything close to the announced capacity additions. NRG's view remains that ERCOT heat rates are overly compressed.

Crane also told investors that it's "clear" climate change legislation, with its inherent prospect of a substantial carbon charge imposed on the American consumer, cannot pass in the current high energy cost environment unless it is coupled with additional elements that hold out at least the

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Michigan PSC OKs Higher Detroit Ed PSCR Factor on Interim Basis

The Michigan PSC approved Detroit Edison's request to implement a revised power supply cost recovery (PSCR) factor of 11.22 mills/kWh on a temporary basis as parties litigate the case (U-15417).

The Commission determined that the temporary factor will provide, "a more immediate and accurate price signal to customers, minimize future rate increases and carrying charges that will be borne by customers, and better match the 2008 PSCR costs to the customers that incurred them," it said in an order.

Detroit Ed is asking for the higher PSCR factor because of "unanticipated" decreases in choice sales, causing bundled load to be higher and resulting in a $43 million underrecovery of its 2007 PSCR. Absent an increase, Detroit Ed reported it would face a $97 million underrecovery by December 31, 2008. The PSCR factor had previously been set at 9.23 mills/kWh.

Detroit Ed reported that it had originally projected electric choice sales in 2008 to be approximately 2,660 GWh but now expects choice sales to be only 1,940 GWh, shifting 720 GWh to bundled service. Detroit Ed blamed the fact that choice customers were not required to notify the utility of their intent to return to bundled service until December 1, 2007, for the inaccurate projection, since it had to submit its PSCR plan two months before that date.

In a reply brief regarding Detroit Ed's application to implement the higher PSCR factor on a permanent basis, the Michigan Environmental Council and PIRG-Michigan argued that Detroit Ed's, "overall message on Customer Choice sales appear inconsistent or counter-intuitive."

MEC and PIRG questioned why the decrease in choice sales was unforeseen and whether the

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Duke Energy Ohio Plans Value-Adding Products Under SmartGrid

Through its SmartGrid initiative, Duke Energy Ohio intends to offer customers, "a variety of new service offerings that cross a broad spectrum," meant to provide customers with more detailed information about their energy usage, the company reported in testimony filed at PUCO (07-589-GA-AIR et. al.).

Among the products envisioned by Duke are prepaid metering and other flexible billing options that would eliminate the need for a security deposit. Additionally, prepaid customers would not have to be subject to a credit check, and would not have to worry about late fees, Duke said.

Another offering would be an improved version of Duke's current Energy Analyzer, a product made available to customers this summer that combines the customer's individual usage history with external weather data to provide information on how weather has impacted their usage. If the customer completes a short survey regarding their home's structure and their energy habits, the tool will then provide an analysis that yields information on how they have impacted their usage and what they can do to save energy. With advanced metering, Duke's intent would be to upgrade the tool to use the daily information to provide an even better energy analysis.

Duke is pursuing its SmartGrid initiative for both its electric and gas distribution systems in Ohio.

SDG&E Would Tie Direct Access Return to AB 1X Residential Protections

Direct access should not be reinstated in California until, among other things, the cross subsidies created by the AB 1X residential rate cap are "addressed," San Diego Gas & Electric argued in comments on inter-utility cost issues that would arise should any Department of Water Resources contracts be novated (R.07-05-025, Matters, 7/10/08).

Under a PUC draft which could be voted on Thursday, the rate cap for California residential customers must last until 2022, when DWR bonds are paid off (Matters, 6/25/08).

SDG&E also argued that it is "absolutely" necessary that a capacity market which ensures the existence of adequate capacity with no free riding or cost stranding, despite migrating retail load, must be implemented before direct access returns.

Also considered essential by SDG&E is that IOUs' cost of capital is adjusted to reflect the debt equivalence impacts of the novation and assignment of DWR contracts, and that the current utility DWR contract allocations, and associated revenue requirement allocations, remain unchanged.

Should the PUC decide to modify the current cost allocation methodology, SDG&E recommended a system that includes a one-time transfer payment that would substantially preserve the current cost allocation compromise. SDG&E touted the simplicity of a one-time transfer payment as preferable to any scenario in which costs must be tracked yearly (providing more instances for IOUs to challenge yearly calculations and allocations), though the utility still prefers not changing the current cost allocation methodology.

The Division of Ratepayer Advocates also favors reaching a decision on cost allocation of novated contracts before starting the novation and negotiation process. Novation in and of itself will trigger the need to revisit cost allocation even if the contract is novated without any change in its terms, DRA observed, because costs would follow the contract. Determining each utility's responsibilities for each contract prior to renegotiation and novation will also enhance negotiation strategies, DRA added.

FERC OKs Affiliate Reporting for CAISO CRR Bidders

FERC accepted additional changes to CAISO's Congestion Revenue Rights rules and Market Redesign and Technology Upgrade tariff, which, among other things, mitigate CRR credit risk caused by load migration and require CRR bidders to disclose affiliates active in other RTO markets (ER08-1059 et. al).

The Commission accepted CAISO's proposed CRR affiliate disclosure requirement, finding that the amended policy is not unduly burdensome and is a reasonable requirement that will potentially benefit all CAISO market participants by limiting the credit risks associated with CRR holders defaulting on their CRR obligations.

Under the arrangement, a CRR bidder must notify CAISO of all affiliates that are CRR Holders, Candidate CRR Holders, or CAISO Market Participants and their guarantors, and any affiliates participating in an organized electricity market in North America. That's narrower than CAISO's original proposal which would have required bidders to disclose all affiliates. Financial marketers, with thousands of affiliates unrelated to the utility industry, had protested the original plan as overly burdensome (Matters, 7/8/08). CAISO would still have the authority to obtain, from a Market Participant that requests an Unsecured Credit Limit, financial and/or other information concerning all of the Market Participant's affiliates.

Originally, the CAISO Tariff and MRTU Tariff did not require LSEs who receive allocated CRRs due to load migration to provide financial security in advance of a CRR allocation. When load migration occurs, counter-flow CRRs are assigned to the load-losing LSE to offset CRRs transferred with the migrated load. CAISO proposed two tariff revisions to mitigate the credit risk that can occur if an LSE cannot meet the credit requirements for holding the counter-flow CRRs it is assigned.

First, FERC accepted CAISO's proposal that if a CRR Holder holds one or more CRRs obtained through a CRR allocation and also holds one or more CRRs obtained through a CRR auction, the individual credit requirements applicable to any of the CRRs obtained through CRR allocation may not be netted against the individual credit requirements applicable to any of the CRRs obtained through a CRR auction in determining such CRR holder's estimated aggregate liability.

Second, the Commission approved CAISO's proposal that each LSE that sells a CRR obtained through a CRR allocation must have an aggregate credit limit with a sufficient margin to cover the credit requirement for holding the offsetting CRR that the LSE would be responsible for assuming in the event of load migration.

FERC Approves Settlement for PJM Reliability Upgrades <500 kV

FERC accepted a settlement that sets the methodology by which PJM will assign the costs of Regional Transmission Expansion Plan reliability upgrades that are planned to operate below 500 kV (ER06-456 et. al). Under the pact, PJM will use a distribution factor (DFAX) analysis methodology for determining the beneficiaries, and therefore who should pay.

The settlement also sets the methodology for assigning cost responsibility for three types of below 500 kV economic upgrades. Cost responsibility for economic-based enhancements or expansions that are modifications of reliability upgrades that are already included in the RTEP shall be assigned based on the DFAX analysis.

For economic-based enhancements or expansions that are accelerations of reliability upgrades that are already included in the RTEP, PJM shall compare: (1) the DFAX analysis and (2) a Locational Marginal Prices Benefits Methodology. If the results from the two analyses indicate at least a ten percentage point cost responsibility assignment differential between the two analyses for any transmission zone, cost responsibility for the period of time the reliability based enhancement or expansion is accelerated shall be assigned using the LMP Benefits Methodology. Otherwise, cost responsibility will be assigned using the DFAX analysis. Additionally, cost responsibility shall be assigned based on the DFAX analysis for all periods other than the acceleration period.

PJM is to make a subsequent section 205 filing covering the methodology for assigning cost responsibility for economic upgrades implemented solely for the purpose of relieving one or more economic transmission constraints.

The assignment of cost responsibility to merchant transmission facilities is to be resolved through the hearing process.

Briefly:

WTU Retail Trimming Price

WTU Retail Energy is cutting the price of its Direct Electricity Plan for West Texas residential customers by 5% to 14.6¢/kWh (based on usage of 1,000 kWh/month), starting in mid-September.

The last price reduction for the plan was on January 1, 2007, and the rate has remained stable since. WTU, an affiliate of Direct Energy, also announced customers will automatically be enrolled to win one of hundreds of gasoline cards, and the REP is also giving away one hybrid SUV.

Two REPs Apply for New Trade Names

Young Energy has applied at the PUCT to add three trade names to its REP Certificate - ABC Energy, Uno Energy, and Connect! Energy. The REP did not formally state that it was dropping one of both of its current trade names (New Electricity and Green Fields Electricity), but the amendment application only listed the three new names under the trade names section. REPs are limited to four trade names by the PUCT. Nooruddin Investments also filed to use the trade names Discount Power and Power Express.

Maine PUC Denies Increase in CMP Uncollectible Adder

The Maine PUC denied a request from Central Maine Power to increase the uncollectible adder in medium and large class SOS sales because Staff is currently reviewing CMP's allocation of partial payments among standard offer and T&D service (2008-239). CMP had requested to increase the uncollectible adder for the medium SOS class from the current rate of 0.2% to 0.4% and the adder for the large SOS class from 0.1% to 0.2%. CMP had explained that charge-offs for those classes have exceeded the monthly retainage amounts over the last year. Although overall retainage balances are sufficient to cover the increase in charge-offs, CMP is concerned that the current economic situation could produce greater charge-offs.

Duke Ohio Seeking 30-Year Peaking and Intermediate PPAs or Asset Ownership

Duke Energy Ohio issued an RFP for up to 1,400 MW of peaking and/or intermediate generating capacity to begin delivery in the 2009-2012 period, through 30-year PPAs or asset ownership proposals for generation resources that will be dedicated to serve its Ohio customers under SB 221. Through the RFP, Duke, "recognizes the need for obtaining long-term traditional supply that is currently provided under short-term arrangements," it said in a statement. Duke will give preference to assets located in the Midwest ISO or which are currently deliverable to MISO. Bids, due Aug. 29, must be of a minimum block of 50 MW. Duke expects to complete negotiations in the first quarter of 2009. Burns & McDonnell will act as an independent third party evaluator for the RFP (DukeEnergyOhioRFP.com).

UGI Competitive Unit's Profit Rises

UGI Energy Services' third quarter net income increased to $9.4 million from $8.2 million a year ago, its parent reported after the market close. Operating income increased $2.1 million, reflecting higher total margin partially offset by higher operating expenses. Total margin from Energy Services increased $3.2 million to $28.0 million, reflecting higher total margin from electric generation, retail electricity sales and, to a much lesser extent, peaking and asset management activities. Those increases in margin were partially offset by lower natural gas total margin from slightly lower sales volumes at lower unit margins. The higher retail electricity and electric generation margin resulted primarily from higher sale prices on 23% higher volumes sold and $1.9 million in mark-to-market gains related to changes in the estimated fair value of Financial Transmission Rights that are used to hedge fixed price sale commitments to customers. Parent UGI Corp. reported higher net income for the third quarter of $15.7 million compared to $11.5 million a year ago, and is holding an analysts call today.

Florida PSC Whacks FP&L Green Program

The Florida PSC angrily ended Florida Power & Light's voluntary renewable energy program after discovering some three-quarters of ratepayers' contributions went to administrative, marketing and management expenses, while only 24% was applied to developing renewable energy facilities. Commissioners were also upset over the use of funds to buy RECs rather than develop in-state renewable projects. Green Mountain Energy, which was contracted to run the program, noted the legitimate and realistic customer acquisition expenses involved in the program. Green Mountain reported that it has fulfilled every customer purchase kilowatt-hour for kilowatt-hour and has supported the construction of 450 kW of new solar electric power in Florida. More than 100% of Sunshine Energy customer revenue has been put back into the program, Green Mountain stated.

OUR TAKE: Green Mountain's observations regarding customer inertia should hopefully correct the hype surrounding customer-driven, mass market green energy, particularly utility-sponsored programs. FP&L's enrollment rate of 38,000 for the green program is less than 1% of customer accounts. Only two IOUs crack the National Renewable Energy Laboratory's top 10 in terms of customer participation, and the highest is Portland General Electric at 8.5% (not surprisingly, the other is another Oregon IOU, PacifiCorp). Only two utilities, both munis, have participation above 10%, and the highest is the City of Palo Alto Utilities at 20%.

The Michigan PSC Staff recently noted acquisition costs for utility green programs range from $50 to $20 per customer at various Community Energy programs, $40 at We Energies, and, from early reports, about $60 at Consumers Energy. Of some newer programs, Detroit Ed enrolled 0.3% of its customer base in GreenCurrents in a little over a year, while Nstar considers it "highly unlikely" that it will crack 8% for its controversial program.

As confirmed by the apparently large marketing expense Green Mountain undertook to drum up a meager 1% participation at FP&L, the vast majority mass market customers are simply not interested in buying green power through utility tariffs, despite the hype of experts and trade press. FP&L's experience and NREL's survey of customer participation rates should give pause to any state regulator considering a utility-offered green program, especially any subsidized, or potentially subsidized, by non-participating ratepayers, given the lack of robust customer demand. It seems obvious that green energy is more effectively developed and put onto the grid (if that is the policy goal), through RPS-type mandates, non-tariffed green programs (e.g., voluntary REC markets or green products offered by competitive suppliers), or favorable wholesale pricing offered by renewable generators (e.g., the desire of LSEs, whether competitive or regulated, to use wind power as a hedge in supply portfolios).

To think of it in another way, if single-digit residential/mass market switching rates are evidence of the failure of electric choice, as critics suggest in many states, shouldn't the same meager percentages indicate the failure of utility green programs, since both essentially involve getting the customer to actively choose something other than their default supply option.

NRG ... from 1

prospect of lower future energy costs. One such element could be a series of nuclear provisions and incentives designed to clear obstacles to the so-called "nuclear renaissance" which would benefit NRG, Crane noted.

Prospects for an electric (plug-in) car title in any climate change legislation would also benefit NRG and the entire electric industry, as transportation, "evolves into the biggest source of electricity demand growth in the years and decades to come," Crane added.

NRG quarterly profits dipped to $129 million from $149 million a year ago on $543 million in pre-tax unrealized mark-to-market losses. Over 60% of the $543 million mark-to-market adjustment is due to hedge ineffectiveness, mainly on NRG's Texas gas slots, resulting from the sharp rise in forward gas prices during a time when power prices did not increase at the same rate. However, NRG told analysts that the long-term gas and power price correlation remains effective.

Excluding the mark-to-market losses, operating income for the second quarter rose 57% to $600 million compared to $383 million in the second quarter 2007. The $217 million increase was largely attributable to the strong performance of NRG's Texas units, including a 24% increase in Texas gas plant generation volume.

Adjusted EBITDA for NRG's Texas units was up 54% to $515 million during the second quarter of 2008 compared to $334 million in the year-ago period. In addition to a return to normal weather patterns compared to last year, higher natural gas prices and higher heat rates during May and early June resulted in higher average power prices during the period. Energy margins increased $139 million due to a $206 million increase in merchant margins, net of settled financial positions, which were partially offset by lower contract margins. The increase in merchant energy margins was driven by a combination of higher market prices and the roll-off of contracted generation positions. Contracted energy margins fell due to lower contracted volumes combined with an estimated $4/MWh decrease in average contracted prices, which reduced margins by $67 million.

NRG's Northeast units recorded second quarter 2008 adjusted EBITDA of $113 million, down $18 million from last year's quarter. The benefits of higher average power prices during the quarter and a 6% increase in generation were offset by the region's hedge position. Contracted net revenues were lower by $18 million compared to the second quarter of 2007 as the cost to serve those contracts rose in line with overall price increases in the market. Capacity revenues were higher by $8 million quarter over quarter as lower New York clearing prices were largely offset by favorable anticipatory capacity hedges and the benefit of a full quarter of PJM Reliability Pricing Model capacity market results.

DTE PSCR ... *from 1*

change itself was also a benefit to Detroit Ed not reflected in the PSCR application (i.e. increasing system charges to be collected by Detroit Ed from choice customers, which equals more base rate revenues).

MEC and PIRG also noted that Detroit Ed has previously claimed that sales lost to Electric Choice represents a "cost" or unacceptable "risk," but is now also arguing that a gain in bundled sales from the erosion of choice sales is creating additional costs.