Energy Choice Matters

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Dynegy Ends Development Joint Venture with LS Power, Citing Credit Crisis

Dynegy is ending a two-year old joint venture with LS Power Associates to develop new generation, citing the constrained credit markets.

Dynegy will acquire exclusive rights, ownership and developmental control of all repowering or expansion opportunities related to its existing portfolio of operating assets. LS Power will acquire full ownership and developmental rights associated with various greenfield projects under consideration in Arkansas, Georgia, Iowa, Michigan and Nevada, as well as other power generation and transmission development projects not related to Dynegy's existing operating portfolio of assets. LS Power will receive approximately $19 million in cash during the first quarter 2009 to reflect the relative value of assets exchanged. Additionally, Dynegy will record a loss in 2009 related to the transaction.

"The development landscape has changed significantly since we agreed to enter into the development joint venture with LS Power in the fall of 2006," said Dynegy CEO Bruce Williamson.

"Today, the development of new generation is increasingly marked by barriers to entry including external credit and regulatory factors that make development much more uncertain. In light of these market circumstances, Dynegy has elected to focus development activities and investments around our own portfolio where we control the option to develop and can manage the costs being incurred more closely," Williamson added.

The dissolution of the joint venture does not affect two projects under construction -- Plum Point in Arkansas and Sandy Creek in Texas -- though Dynegy is re-evaluating future participation in both projects. Dynegy has previously sold portions of its interests in both coal-fired projects. Dynegy

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NYISO Seeks Tariff Change to Schedule All But Fixed Block Units Earlier in SCUC

The NYISO has proposed amending its tariff to use "Pass 5" of its Security Constrained Unit Commitment (SCUC) process to establish schedules for all but Fixed Block Units, and to use Pass 6 to establish Fixed Block Unit schedules.

The NYISO's day-ahead market software (SCUC) uses several processes or "Passes" to establish schedules and prices for all day-ahead committed resources. The current tariffs establish day-ahead prices in Pass 5, and day-ahead schedules in Pass 6.

As a result, SCUC's resource schedules may differ from the prices it establishes for those resources due to an embedded rule difference between SCUC's price-setting and schedule-setting logic. The embedded rule difference allows inflexible but fast-starting gas turbines (known as Fixed Block Units) to set price (called hybrid pricing). In Pass 5, these Fixed Block Units are dispatched flexibly between zero and their minimum generation levels for purposes of setting price. However, Pass 6 reflects the Fixed Block Units' actual physical operating requirement to run at full output. Other units are redispatched due to this requirement.

NYISO explained that the difference between the price-setting and schedule-setting logic in its current day-ahead SCUC process results in some units receiving schedules inconsistent with their price, making the units uneconomic. While internal generators and import transactions experiencing schedule modification as a result of the Pass 6 redispatch are eligible for Bid Production Cost Guarantee (BPCG) payments to compensate them for the difference between their revenues and

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Four Bidders Win FirstEnergy Ohio Interim RFP

A competitive RFP for interim power supplies for the FirstEnergy Ohio distribution utilities yielded an average winning bid price consistent with a retail rate of 6.98¢/kWh, FirstEnergy said Friday. Customers will still be charged the existing rate as of December 31, 2008.

FirstEnergy held the RFP after PUCO modified FirstEnergy's Electric Security Plan for Ohio Edison, Cleveland Electric Illuminating and Toledo Edison, and FirstEnergy decided to withdraw the ESP due to the changes (Matters, 12/23/08). Supply was procured for the period January 5 through March 31, 2009.

A similar bid process is being planned for supplies beyond March 31, 2009. Ultimately, FirstEnergy anticipates that customer prices for generation will reflect market prices.

The RFP had four winning bidders, one of which was FirstEnergy Solutions. The RFP was conducted on December 31 by CRA International.

NYISO Modeling Error Shows Need for Transparency, DC Energy Says

The identification of a modeling error in the New York ISO's Security Constrained Unit Commitment (SCUC) software illustrates why greater transparency into RTOs' modeling and data is needed, DC Energy said in comments at FERC (ER09-405, Matters, 1/2/09).

The modeling error, reported to FERC on December 11, was made on January 8, 2008, and caused the SCUC to set schedules and prices in the day-ahead market using an expectation of greater available transmission capacity from western New York to eastern New York than would be physically available in real-time market operations.

DC Energy told FERC it first alerted NYISO staff of what DC Energy believed to be a NYISO scheduling error on January 23. DC Energy said it was able to detect the error, notify NYISO, and therefore minimize the harm to the market, as a result of publicly available data.

Noting the ongoing debate concerning the amount of publicly available data and the lag with which such data is posted, DC Energy argued a lack of transparency decreases market efficiency and increases overall risk premiums and costs to consumers.

"With greater transparency, market participants can function as an early warning system," DC Energy said. Greater transparency, especially at the seams between regions, is a "missing element" to ISO/RTO market design, the financial marketer added.

Accurate modeling of the ISO market requires load, generation and transmission data as well as model assumptions, and such information should be publicly available, DC Energy contended.

"The uncertainty and delay in bringing about solutions to market problems is mostly due to the lack of transparency, as well as perhaps in some cases the ISO/RTOs' lack of resources," DC Energy continued.

The time it took between DC Energy's notification of the SCUC modeling error and the NYISO's filing was more than 10 months. "This should not occur," DC Energy said.

While DC Energy noticed the problem, it had a hard time convincing NYISO of the error without more definitive data.

Despite being financially harmed by the modeling error, DC Energy supports the NYISO's recommendation to not re-state prices due to the error, as DC Energy believes retroactive price correction would create uncertainty and undermine confidence in markets.

However, Alcoa "vigorously" protested NYISO's request for a waiver of refund requirements associated with the modeling error.

Alcoa noted the modeling error waiver is the second filing by NYISO relating to the substantial increase in uplift costs experienced within the NYISO in January of 2008, with the first relating to the scheduling of transactions via circuitous paths around Lake Erie to avoid congestion charges.

The increase in uplift charges, "requires thorough investigation and explanation before the fairness of NYISO-administered markets can be judged on something more than mere faith," Alcoa said.

"To protect consumers, the Commission must enter into an investigation sufficient to assure that all of the causes of market dysfunction that resulted in the dramatic increase in uplift charges have been identified, and that appropriate changes have been implemented to prevent recurrence of such uplift charges," Alcoa argued.

DPUC Opens Investigation into Submetering by Property Managers

The Connecticut DPUC has opened a proceeding to review submetering of electricity by Energy Management Systems (EMS) at buildings under the management or control of PMC Property Group (PMC) and elsewhere in Connecticut.

While investigating an electricity metering complaint from a PMC tenant, PMC acknowledged to the Department's Consumer Services Unit that it has been sub-metering electricity at the subject property (55 Trumbull Street, Hartford, Connecticut), and at other Connecticut properties without Department approval.

It was also brought to light that PMC's submetering service provider, EMS, provides submetering services at other Connecticut properties not under PMC's control or management.

Connecticut law generally prohibits submetering in new dwellings with separate cooking facilities, although exemptions may be permitted by application. Master and submetering is allowed at recreational campgrounds and individual slips at marinas, and exemptions have been granted for publicly financed elderly housing under certain conditions.

Otherwise, the DPUC generally prohibits submetering because it removes legal protections inherent in the utility-customer relationship, and also deprives customers of choice in the retail market.

Nucor Opposes Rehearing of FirstEnergy MRO Without Time-Based Rates

Nucor Steel objected to FirstEnergy's rehearing request regarding PUCO's denial of the utility's Market Rate Offer, arguing that FirstEnergy has failed to incorporate interruptible and time-of-day rates into the MRO rate design.

FirstEnergy's proposed MRO would have used uniform, volumetric rates. In its order rejecting the MRO (Matters, 11/26/08), PUCO agreed time-based rates were necessary to advance the state policies articulated in Section 4928.02 of the Revised Code. In its rehearing request, FirstEnergy argued the statute does not specifically require use of interruptible and time-of-day rates, and thus an MRO need not include them.

"The statute, however, is completely silent on the particular rate design elements that must be included in an MRO. FirstEnergy interprets this silence to mean that FirstEnergy can propose any rate design it wants, and the Commission is powerless to modify or reject it. This argument is absurd on its face," Nucor said.

Nucor asserted that PUCO retains "broad authority" to approve and implement the rates, proper cost allocation and rate design under an MRO, particularly since certain rate designs, such as time-of-day rates, can help achieve statutory policies, including demand-side management.

"Apparently, FirstEnergy believes that it merely needs to present some minimal degree of evidence that its MRO plan meets the eight criteria for a competitive bidding process specified in Section 4928.142 of the Revised Code, and the Commission is required to rubber-stamp FirstEnergy's entire MRO proposal," Nucor charged.

In addition to requiring interruptible and time-of-day rates as part of the MRO, Nucor urged PUCO to require that costs be allocated under the MRO rates in a manner that retains the current rate relationships between customer classes, and that recognizes the cost differences to serve the various customer classes.

Nucor has argued that FirstEnergy's proposed uniform volumetric rate design would result in the over-allocation of costs to the industrial classes. Nucor noted FirstEnergy's previously proposed 2007 competitive bidding plan included interruptible and time-of-day rates.

FERC Approves MISO Plan for Intra-Period FTRs

FERC accepted a proposal from the Midwest ISO to allow for the partial-year, intra-period allocation of Financial Transmission Rights

(FTRs). While the ability of customers in new Auction Revenue Rights (ARR) zones to receive a partial-year allocation of these rights was originally sought to accommodate integration of Duquesne Light into MISO, the tariff provisions are generally applicable and address any future request seeking to add a new ARR zone on a mid-cycle basis.

The Midwest ISO did not provide details in its filing regarding the procedures for the partial-year allocation of FTRs among customers in the new zone. By contrast, the Midwest ISO has detailed procedures for allocating annual ARRs. The Midwest ISO provided no mention of which, if any, of the existing ARR allocation provisions will be incorporated into its proposed partial-year allocation process.

Thus, FERC ordered that no partial-year FTRs will be allocated to customers in a new ARR zone absent a prior section 205 filing detailing how FTRs will be allocated during the partial year. In providing additional details as to how FTRs will be allocated, the Midwest ISO must also address whether more than one stage of allocation will be used to prioritize existing uses for allocation of financial rights, how the allocation will occur in each stage, and how the FTRs will be allocated in different months of the remaining partial year, FERC ordered.

In addition, such partial-year FTR allocations should be based upon a simultaneous feasibility study reflecting the actual date of the transmission owner's integration into the Midwest ISO, when that date is known, FERC said.

Mass. DPU to Review Nstar SEMA Uplift Costs

The Massachusetts DPU will investigate the Cape Light Compact's concern regarding Southeastern Massachusetts (SEMA) zone uplift costs that are reconciled in Nstar's basic service adjustment factor, it said in an order accepting Nstar's proposed annual transmission and basic service rate adjustments subject to future reconciliation (08-55).

Cape Light argued that Nstar undercollected for basic service through September 2008 for the SEMA zone's uplift charges. However, Cape Light noted that Nstar claimed a $27.0 million overcollection for 2008 and, therefore, must have overcollected from other components of basic service rates to offset the SEMA undercollection. Cape Light Compact estimated that Nstar has undercollected over $6.0 million dollars through September 2008 for SEMA uplift charges alone. As a result, Cape Light contended that Nstar must have overcollected approximately $33.0 million from other components of basic service rates in 2008.

The DPU determined that further investigation is necessary because the proposed transmission and basic service rate adjustments are based upon part-actual (seven months) and part-estimated (five months) data for 2008, which will be updated to actual rates in 2009 consistent with previous reconciliation filings.

Briefly:

Nstar Suggests Real-Time Recovery of All Bad Debt

The Massachusetts DPU should consider allowing utilities to recover 100% of all bad debt write-offs on a real-time, reconciling basis, Nstar said in comments in a rulemaking addressing added disconnection protections for customers (08-104). Otherwise, electric and gas companies could be forced to file for exogenous-cost recovery or base rate cases to address any added costs of expanded protections, Nstar said.

FERC Revokes MBR Authority of Flat Earth Energy

FERC revoked the market-based rate authority of Flat Earth Energy for failure to file Electric Quarterly Reports.

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currently owns approximately 20 percent of the 665-megawatt Plum Point project and approximately 30 percent of the 900-megawatt Sandy Creek project.

As the bulk of the joint venture's new projects were coal-fired, environmental groups were quick to take credit for Dynegy's exit, after waging a public relations campaign against the IPP's big investment in coal.

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offers, export and wheel-through transactions, price-capped load, and virtual resources are not eligible for such payments. Upon investigation, NYISO discovered these unreimbursed costs average $4,200 per month on export transactions and price-capped loads that are not eligible for a BPCG payment.

To alleviate this problem, NYISO proposed setting schedules for all but Fixed Block Units in Pass 5. Under the proposed changes, the schedules of other units will no longer be adjusted to offset any excess capacity that may be scheduled on the Fixed Block Units in Pass 6.

The modification will reduce statewide uplift by eliminating BPCGs paid day-ahead on account of the uneconomic scheduling of resources, and will improve the allocation of costs associated with hybrid pricing, NYISO said.

While establishing schedules in Pass 5 will eliminate these BPCG costs, it may increase or decrease the size of the energy residual assigned to loads. Energy residuals are assigned to loads hourly.

As a result, NYISO said its proposed amendments will also improve the fairness of the allocation of costs (or revenues) incurred as a result of hybrid pricing, by assigning such costs to load in the market in any hour in which Fixed Block Units' physical schedules deviate from the output that was flexibly dispatched for them in Pass 5.

The NYISO's analysis estimates that the market impact of the SCUC changes on residuals will range from a $150,000 charge to an $180,000 credit per month. The change to SCUC will result in a market-wide average decrease in net-residual charges of $4,700 per month, NYISO said.

FERC rejected a similar proposal from NYISO in 2002, citing concerns about potentially higher uplift costs. FERC, at that time, said it would address opportunity costs for generators backed down to accommodate fixed block generators in the Standard Market Design proceeding. NYISO noted the Standard Market Design effort was terminated and did not result in changes to address the lost opportunity costs. Furthermore, the growth of virtual bidding since 2002 has added a significant number of additional participants that experience the negative impacts of uneconomic scheduling, NYISO said.

NYISO argued its proposal to reflect costs incurred due hybrid pricing in energy residuals, which are recovered hourly, rather than in BPCGs, which are recovered daily, better allocates these costs to those in the market at the time the Fixed Block Units were scheduled. Experience since 2002 shows that the cost of not pursuing a better alignment of schedules outweighs the costs of doing so, NYISO claimed.