Energy Choice Matters
April 30, 2008

PUCO to oppose Duke Generation Transfer at FERC

PUCO Chairman Alan Schriber attacked a proposal by Duke Energy Ohio to transfer ownership of some 7,800 MW of generation to 22 new LLCs that will be indirect subsidiaries of Duke Energy Ohio's parent, Cinergy.

"The motive behind the timing of Duke's announcement is, at best, suspect," Schriber suggested in a statement.

Accordingly, PUCO will intervene in the FERC docket (EC08-78), "to ensure that Duke's filing is not an attempt to skirt our recently passed legislation, Substitute Senate Bill 221."

"The [Ohio] Commission's Order on Remand affirming Duke's Rate Stabilization Plan prohibits the company from divesting its generating assets through Dec. 31, 2008," Schriber explained.

The General Assembly, in passing Substitute Senate Bill 221, has extended that prohibition into 2009 and beyond, he added, since the bill specifically states that no electric distribution utility can sell or transfer generating assets without obtaining prior PUCO approval.

Duke told FERC that ratepayers are doubly protected in the transaction since, "they have retail choice and are served at market-based rates."

The last part of the statement would probably turn a few heads at the state legislature, as lawmakers certainly don't consider any of the current rates in the state to be market-based, since they just established a process which could allow distribution companies to move to market-based rates. SB 221 contemplates that electric distribution companies still owning generation cannot move to market-based rates until 2014, at the earliest.

Duke Energy Ohio reported that is has no retail power sales customers served at cost-based rates.

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FERC Approves CAISO Penalties for Declined Dispatches

FERC accepted changes to the California ISO's tariff to impose penalties on scheduling coordinators who fail to deliver on, or "decline," pre-dispatch bids for import and export real-time energy (ER08-628).

The ISO will impose charges if a scheduling coordinator's "declines" exceed both 300 MWh and 10% of their pre-dispatched import or export bids in a trading month (Matters, 4/17/08). The fees are designed to minimize excessive pre-dispatched bid declines which can harm reliability and also thwart market rules if participants treat pre-dispatched real-time energy bids at the interties as a cost-free option to sell or buy energy.

FERC found the penalties balance market flexibility with the need to maintain reliable grid operations. The 10% threshold is high enough so as not to discourage market participants from submitting import and exports bids, FERC concluded, and will still accommodate bid declines that are beyond the scheduling coordinator's control, such as curtailments by reliability authorities, derates of transmission lines or generation outages. CAISO's analysis shows that a 300 MWh threshold has a minimal impact on scheduling coordinators in the market, FERC observed.

FERC directed the ISO to submit a compliance filing that clarifies that anti-manipulation provisions remain in full force in addition to the specific decline penalties.

The changes will be reflected in both the ISO's current tariff and the Market Redesign and Technology Upgrade tariff.

ALJ Recommends Disallowing $2.7 Million in Consumers GCR

Although Consumers Energy presented sufficient evidence to demonstrate that it needed additional quantities of gas to meet colder than normal conditions in March 2007, the LDC failed to prove that its decision to purchase additional quantities of gas to meet that need, rather than using gas from storage, was reasonable and prudent, an ALJ ruled in a proposed decision (U-14716-R).

The ALJ would disallow Consumers from collecting $2,710,500 gas cost recovery (GCR) charges stemming from the purchased gas.

Consumers, the ALJ reasoned, did not support its testimony that storage withdrawals depend on weather and are also limited by other system constraints such as compression, field capability and transmission capability, nor did the LDC sufficiently link such constraints in developing its figure that only 20,125 MMcf of gas was available for withdrawal for March 2007 instead of a much higher figure suggested by the Residential Ratepayer Consortium (RRC).

Consumers claimed that the data supporting its position was confidential for security reasons, but the ALJ noted the LDC did not file for a protective order.

"Consumers' failure to provide information regarding the maximum daily withdrawals from its base load fields and, instead, simply indicating that such estimates are not made raises further questions regarding its estimate of storage withdrawal availability," the ALJ added.

"As the RRC so aptly points out, if the Company does not make estimates of maximum daily withdrawals from each of its nine base load fields, how could it estimate total maximum storage withdrawals for March 2007?"

N.Y. Transmission Owners Say Dynegy Refund Request Too Late

Dynegy's request to collect $6.2 million in a case involving the New York ISO's under-commitment of capacity back in 2002 should be denied, Consolidated Edison, the New York Power Authority and other transmission owners told FERC (EL05-17).

In 2004, KeySpan-Ravenswood filed a complaint alleging that the NYISO under-committed capacity for the 2002 summer. Although FERC denied the complaint, the Court of Appeals for the D.C. Circuit remanded the case to FERC, agreeing with KeySpan that the NYISO had under-committed, and directing the Commission to determine what, if any, refunds should be granted.

Through alternative dispute resolution, ConEd, NYPA, ConEdison Solutions, Constellation NewEnergy, KeySpan Energy Services, Strategic Energy, Hess Corporation and Econnergy reached a settlement with KeySpan in which the parties would pay KeySpan $5 million. The settlement was filed with FERC in October of last year, and Dynegy and NRG Energy opposed the settlement.

Dynegy recently asked FERC to direct the NYISO to issue refunds to, "every affected market participant," reporting that it was not informed of the settlement negotiations. Dynegy argues that not only did NYISO's under-commitment depress in-city capacity prices, but also lowered rest-of-state prices as well, costing capacity suppliers nearly $21 million.

But Dynegy has no entitlement to relief in the remand proceeding because the IPP failed to timely raise a claim of harm and failed to preserve any such right, because it neither sought rehearing of the Commission's order nor appealed that order, ConEd and NYPA claimed.

"Dynegy inexcusably slept on its rights for over six years and its claim is precluded by the equitable doctrine of laches," ConEd and NYPA added.

Allowing Dynegy to raise a claim at such a late date would create a level of uncertainty in the NYISO markets that would be, "very harmful to both suppliers and customers," ConEd and NYPA argued.

"Neither suppliers nor customers would ever be able to rely on the settled NYISO market prices," ConEd and NYPA warned.

ConEd and NYPA attacked Dynegy's claim for $6.2 million as based on unsupported hypothetical assumptions, and explained that refunds of the nature requested by Dynegy cannot be calculated at this late date with any reasonable degree of certainty. Such refunds would thus, "unjustly establish a precedent casting doubt on future results of the market," ConEd and NYPA cautioned.

Reliant Energy, a capacity supplier in the 2002 in-city and rest-of-state capacity auctions, backed Dynegy's claim, however, reporting that it was also not invited to or informed of settlement talks.

The D.C. Court has found that the NYISO violated its filed rate, and Commission policy is to ensure that all affected market participants are made whole in such instances, Reliant argued.

BGE Cautions Against Myopic View of Demand Response Cost Effectiveness

The Maryland PSC, "seems to have adopted a policy of deferring any cost recovery of new DSM program until some future date in order to meet a 'no bill increase today' criterion," Baltimore Gas and Electric observed in a letter regarding its request to accelerate cost recovery from demand response programs by one year (Matters, 4/29/08).

Deferred costs, BGE reminded, must be financed and ultimately paid back by customers. BGE's PeakRewards and conservation programs will require hundreds of millions of dollars in up-front utility investment, and customers will see lower long-term bills if there is timely cost recovery of those costs, BGE argued. "Customers will not benefit from having interest costs needlessly layered on top of higher electric prices 3-5 years from now," BGE noted.

BGE expressed "grave concerns" with criteria used by PSC staff and the Office of People's Counsel to evaluate demand side management projects that are alternatives to new generation, cautioning that the criteria could prevent "least cost" alternatives to new generation from coming forward, ultimately causing higher power prices or even "severe" electricity shortages.

Staff has argued that two basic criteria govern evaluation of demand side management -- achieving maximum demand reduction, and minimizing program costs.

But those two criteria are often at odds, BGE pointed out. While some would argue the "least cost" alternative is to do nothing, that will only keep short-term costs low and will either result in the supply/demand gap being filled by costly new generation, or rolling blackouts, BGE cautioned.

BGE noted that lowering the bill credits and upfront signing bonuses for its PeakRewards program could jeopardize its 600 MW goal for 2011, leaving the market to substitute $600-800/kW peaking generation for $165/kW PeakRewards capacity.

BGE suggested that customers understand some up-front investment is required to achieve long-term savings, pointing to customers buying hybrid vehicles at a premium to realize gasoline savings. "If the criteria [for new car shopping] were I will just buy the lowest priced car, Yugo would still be in business," BGE claimed. But instead, customers are typically making a car buying decision that gives them quality that they need and the lowest overall cost of ownership, which includes long-term fuel savings.

BGE thinks demand side management programs should be evaluated based on their cost-effectiveness compared to meeting load growth through new generation.

D.C. Water and Sewer Authority Protests Risk Allocation in Pepco PPA Fund

Pepco's treatment of a $450 million settlement payment from Mirant relating to a back-to-back arrangement does not fairly allocate the risk between Pepco and D.C. customers in, "the rapidly changing markets for electric capacity and energy," the District of Columbia Water and Sewer Authority (WASA) told the D.C. PSC (FC 945).

Pepco has proposed using $320 million from the settlement to create a special fund to be used to pay the difference between Pepco's costs of its purchases under a PPA with the Panda-Brandywine power plant and the market value of those purchases (Matters, 2/26/08).

WASA objects to Pepco's proposal to allocate to itself a portion of the difference between the back-to-back settlement payment and the $320 million.

WASA is also concerned that Pepco's proposal could shift to D.C. customers all of the risk that the $320 million may be insufficient to fund the difference between the market value and the costs of the PPA capacity and energy over its remaining life (some 13 years).

Pepco should be required to share some of that risk if it retains some of the settlement payment, WASA argued.

"Simply put, Pepco is proposing, based on its own consultant's long-term projection of electricity markets, to pocket a portion of a settlement payment that was intended to protect DC customers against their exposure to the Panda PPA, while placing on DC customers all the risk that Pepco's projection may turn out to be wrong," WASA cautioned.

MMC Fires Back at CAISO in Aggregated Units Dispute

The California ISO, "cannot induce a Market Participant to spend millions of dollars in reliance on the existing regulatory regime and then change its interpretation of those rules after the investment is made," MMC Energy charged in an answer regarding the ISO's view that MMC's aggregated units do not qualify as spinning reserves (EL08-46).

MMC Energy renewed its claims that senior CAISO management were aware of the aggregated units' designs and did not raise objections to their participation in the spinning reserves market during certification.

While CAISO argued its tariff clearly prohibits the aggregated units (Matters, 4/15/08), MMC replied that the ISO for two years interpreted the tariff as allowing aggregation units in the spinning reserves market, and asked FERC to hold CAISO to its prior interpretation of the currently effective tariff, since otherwise the ISO would be in violation of the field rate doctrine.

While the CAISO has rejected bids from the aggregated units based on reliability grounds, MMC argued that its units actually, "provide valuable system reserves in a congested portion of the CAISO system thereby enhancing, not degrading, system reliability."

MMC claimed that nothing in the WECC-BAL-002 standard cited by the CAISO prohibits aggregated units from participating in the spinning reserve market based on their aggregated capacity.

Briefly:

Conn. Retailers Must Still Offer 12-Month Payment Plans for Time Being

The DPUC refused to alter its requirement that retailers collecting back billings stemming from Connecticut Light and Power's time-of-use billing errors must offer customers at least a 12-month payment plan, until the DPUC issues a final order in the case (08-02-06). The DPUC did rule, however, that customers may elect to pay the entire back billing charges in one lump sum up front or over a shorter period, as long as they are notified of the option for a 12-month payment plan, a request made by several retailers (Matters, 2/28/08). The Department also clarified the requirement to offer a payment plan only applies to customers with outstanding balances; the plan does not have to be offered to customers who have already paid the back charges.

SPP Studying Use of ERCOT Retail System for Entergy Integration

The Southwest Power Pool has been working with ERCOT staff to understand customer data which would be available via ERCOT's retail system and how that data could be used for scheduling and settlement within the SPP framework as part of SPP's review of the possible integration of Energy Texas into SPP to enable retail choice in Entergy's service territory (PUCT docket 33687). SPP is also evaluating market power, necessary transmission to alleviate market power, and the identification of the functionality and rules needed to support retail open access for Entergy Texas as part of SPP. SPP has scheduled informal conference call for May 8 to address data included in its study models and set its next in-person stakeholder meeting for June 20.

ICC OKs ComEd SOS REC Purchases

The Illinois Commerce Commission approved Commonwealth Edison's REC procurement for SOS from June 1, 2008 through May 31, 2009. By law, 2% of SOS sales must be green, although the green power can't cause rates to rise more than 0.5%. Winning bidders included Beecher Energy, Constellation Energy Commodities Group, Exelon Generation, FPL Energy Power Marketing, PPM Energy, Sempra Energy Trading, Sterling Planet and WM Renewable Energy. The load weighted average of the winning bid prices for each contract type and for each contract term are:

Final Average Prices ($/REC)

	Wind RECs	Non-Wind RECs
Illinois	35.72	21.85
Adjoining State	18.35	5.74
Other State	7.34	4.25

Bangor Hydro Preparing Smart Meter Plan

By the end of May, Bangor Hydro-Electric is to submit a plan to the Maine PUC for installing time-of-use meters for all customers in its D-1 and D-2 classes, and for the recovery of the net costs of the meters. The plan is to also include proposed pricing that time differentiates the demand charge component of distribution rates for those classes, to be used once the meters are installed (dockets 2006-661, 2005-554). The PUC staff is to draft a request for comments that seeks input from suppliers as to the types of supply products that can made possible through advanced metering to facilitate discussion of a process to further consider the use of advanced metering to allow for dynamic pricing.

New Face at Fortis

Fortis Energy Marketing and Trading named Bruce Sukaly as Managing Director, Asset Management. Sukaly joins Fortis from Constellation Energy Commodities Group where he spent over a year as Vice President, Energy Investments and was previously Chief Commercial Officer for Cinergy Marketing and Trading

Duke Ohio Generation *... From 1*

Its retail power sales customers are served at market-based rates that are not tied to ownership of generation and will not be affected by the sale of the generating facilities, Duke Energy Ohio told FERC.