Energy Choice Matters

July 17, 2009

Panda-Brandywine Casts Doubts on CPV's Ability to Perform Under Long-Term Contract

Certain statements made by Charles County, Maryland, in the course of a federal court case, "raise doubts about CPV's ability to perform under long-term power purchase contracts," Panda-Brandywine said in a motion to lodge at the Maryland PSC, in response to CPV Maryland's petition that utilities be compelled to contract for the output from CPV's St. Charles plant.

Specifically, the outcome of litigation between Panda-Brandywine and Charles County will impact whether the County can meet terms of a development agreement it has with CPV, Panda-Brandywine said, seeking to lodge the record of such litigation into Case 9117 at the PSC.

At issue in the federal litigation is Panda-Brandywine's right to 2.7 million gallons per day (MGD) of treated effluent from the County for its peak cooling needs, under a contract signed in 1994.

In order to meet the needs of CPV, the County is seeking a declaratory ruling from a U.S. District Court stating (1) that Panda cannot use the treated effluent for any expansion of the Brandywine facility beyond the existing 230-MW power plant, and (2) that Panda cannot resell treated effluent to third parties. Panda-Brandywine is opposing the requested declarations as inconsistent with its 1994 contract.

Panda-Brandywine alleged that the County is seeking the restrictions, "for one purpose and one purpose only - to enable the County to supply 5.4 MGD of treated effluent to the proposed CPV power plant."

Most important to the matter before the PSC is that without the sought restrictions, according to the County, the availability of treated effluent would not be sufficient to accommodate both the existing Brandywine and proposed CPV facilities. The County has said in court pleadings that it can only meet its obligations under the existing Brandywine contract and the CPV development

Continued P. 6

FERC Does Not Address Case-By-Case Approval of Retail Customer Load Response

FERC denied rehearing on almost all aspects of its order on wholesale competition in organized electricity markets (Order 719), but the lack of any discussion on point regarding the ability of relevant electric retail regulatory authorities to approve customer-by-customer participation in RTO demand response programs likely means the questions will continue to be contested. While FERC's rehearing order broadly contains language that is more deferential to retail authorities with respect to demand response aggregation, the order does not address the specific question of whether a retail authority may allow one retail customer to participate in an RTO demand response program, while denying such participation to a similarly situated customer (RM07-19).

The question has become most controversial in PJM, where, in a compliance filing, PJM would prohibit retail authorities from imposing such "one-off" approvals of demand response aggregation (i.e. using a case-by-case approach under which one customer may be approved for RTO demand response participation but another customer may be denied). PJM would require the retail authority to either allow all retail customers to participate in RTO demand response programs, or prohibit all customers from such participation. Municipals and certain state regulators have argued that Order

Continued P. 6

AOBA Opposes BGE Customer List Proposal

The Apartment and Office Building Association of Metropolitan Washington opposed Baltimore Gas & Electric's request to make customer lists available to competitive suppliers, arguing that such customer information sharing is prohibited by the state's annotated code.

As only reported by *Matters*, BGE has requested permission to distribute customer lists to suppliers free of charge. Customers would be allowed to opt-out of having their information shared, with notification on bill inserts (Matters, 5/4/09).

AOBA argued that the Maryland Annotated Code provision on electric restructuring "clearly prohibits" disclosure of customer account information by an electric company or competitive supplier absent the prior consent of the retail customer. Section 7-505(b)(6) of the Public Utility Companies Code provision provides that, "The Commission shall issue orders or regulations to prevent an electric company and an electricity supplier from disclosing a retail electric customer's billing, payment, and credit information without the retail electric customer's consent, except as allowed by the Commission for bill collection or credit rating reporting purposes," AOBA said.

AOBA noted that the legislature has rejected such customer list proposals previously, and said BGE has offered no new rationale or legal basis for implementing its proposal.

The customer opt-out provision in BGE's proposal is impractical and unworkable, AOBA said, stating that non-residential account numbers frequently change as properties are bought and sold and management companies are changed. "Most often the customer does not know exactly when the account number has or will change and is not even aware of the change until after it happens. Under these situations, it would be difficult for a customer to keep on top of continually opting out of customer lists," AOBA said.

FERC Says Lake Erie Loop Flows Did Not Involve Manipulation

FERC said no market manipulation or tariff violations occurred in circuitous power transactions around Lake Erie that increased loop flows and uplifts in the New York ISO during the first half of 2008, in releasing an Office of Enforcement report. FERC also directed NYISO and neighboring RTOs to develop a long-term comprehensive solution to the loop flow problem, including addressing interface pricing and congestion management, with a report and any tariff revisions due within 180 days (ER08-1281).

Adopting the findings of the enforcement staff's report, FERC said that the uplift experienced by the NYISO's customers, as a result of Lake Erie region scheduling practices between January 1, 2008 and July 22, 2008 was due, in substantial part, to: (i) the lack of seams coordination among the NYISO and neighboring RTOs, including PJM, the Midwest ISO, and Ontario's Independent Electricity System Operator; (ii) the incentives created by certain proxy bus pricing changes that the NYISO put into effect in 2007; and (iii) the NYISO's methodology for incorporating loop flow in NYISO's day-ahead modeling.

"[W]hile the circuitous schedules examined in the investigation did appear to contribute to loop flow, they were openly placed as an economic response to price signals and did not constitute a fraudulent device, scheme or artifice," FERC said. Thus, no further action (including the awarding of refunds, disgorgement of profits, civil penalties, mitigation measures, or other requested remedies) is warranted, the Commission added.

While Multiple Intervenors argued that the transactions should have been mitigated under Attachment H of the NYISO tariff, FERC said that Attachment H only applies mitigation for three specific types of conduct: physical withholding, economic withholding, or uneconomic production of electric facilities -- and the circuitous scheduling did not involve any of those three types of conduct.

FERC reported that nine market participants scheduled flows on the so-called "Path 1" contract path, which was believed to be causing market inefficiencies. Three participants scheduled flows on "Path 5." Among those named in the FERC report are: Constellation Energy Commodities Group, DTE Energy Trading, Fortis Energy Marketing & Trading, MAG Energy Solutions, Rainbow Energy Marketing, Saracen Energy Partners, Silverhill, and TransAlta Energy Marketing.

"[M]arket participants were openly responding to price signals, were not artificially affecting those signals or deliberately affecting congestion in order to raise prices, and did not commit market manipulation," FERC said.

While FERC agreed that a pricing incentive was created by the combination of NYISO's and PJM's different pricing methodologies and the divergence between the Bruce and Keystone Proxy Bus prices, the Commission held that the existence of a pricing incentive is suggestive of the lack of a fraudulent device, scheme or artifice, and is indicative instead of market participants responding to existing prices, rather than artificially affecting them.

"The market participants did not act against their economic interests or attempt to artificially affect price, which are hallmarks of market manipulation. And the market inefficiencies NYISO complains of were not created by the market participants, but by the price signals themselves (and ultimately by the RTOs designing the price signals)," FERC said.

"The fact that deleterious effects (to NYISO) may have resulted from these pricing incentives suggests not manipulation, but the need for a market redesign," FERC said.

Although the circuitous schedules may well have been a contributing factor in the Lake Erie loop flows in the first half of 2008, they were certainly not the entire reason for those flows, FERC added, citing other potential operational causes as well as inflated natural gas prices. The Commission said the impact of the circuitous schedules on uplift is "indeterminate" due to such other factors.

While the circuitous schedules did appear to contribute to loop flow, market participants are not well situated to try and predict loop flow effects in real time, which are dependent on a complex interaction of ever-changing system configurations and schedules, FERC added.

Although NYISO raised concerns that market participants might be disguising the true source and sink of transactions and scheduling transactions using multiple tags, FERC's review of data failed to show participants scheduling any but a de minimis number of transactions from MISO into NYISO for the same hour as they scheduled Path 1 transactions. FERC concluded that market participants were not concealing the true source and sink of their transactions, as the source and sink, as well as all wheels, for the Path 1 and Path 5 transactions are clearly visible on the NERC tags.

Md. Grants Additional Broker Licenses to Unlicensed Firms, Levies Fines

The Maryland PSC granted licenses to three additional brokers that had previously conducted operations in the state without the requisite license, applying a penalty of the greater-of $100 or the uncollected Commission assessment on each company, consistent with Staff's recommendations.

Amerex Brokers received both electric and natural gas broker licenses, to serve non-residential electric customers at the four investor-owned utilities plus Choptank Electric Cooperative and the Southern Maryland Electric Cooperative, and non-residential gas customers at Baltimore Gas and Electric, Washington Gas Light, Columbia Gas, and Chesapeake Utilities. Amerex was ordered to pay a penalty of $132 related to its unlicensed electric brokering, and $100 related to its unlicensed gas brokering.

Platinum Advertising II was granted both an electric and gas brokering license to serve non-residential electric customers at BGE, Delmarva and Allegheny Power, and non-residential gas customers at BGE. Platinum Advertising II was ordered to pay a penalty of $100 for its unlicensed electric brokering, and $100 for its unlicensed gas brokering.

The PSC granted Texas Energy Options an electric broker license for non-residential customers at BGE, Delmarva, and Pepco. Texas Energy Options was ordered to pay a penalty of $100 for its unlicensed electric brokering.

N.Y. PSC to Adopt Corning JP Introducing MFC

The New York PSC intends to adopt a joint proposal in Corning Natural Gas' rate case that would establish a Merchant Function Charge applicable to Corning SC 1, Corning SC 2, Corning SC 5, Bath SC 1, Hammondsport SC 1, and Hammondsport SC 2 customers. The PSC did not adopt the joint proposal at a meeting yesterday, as it elected to issue a show cause order to Corning as to why the proposal should not be adopted with an earnings sharing mechanism added to it (08-G-1137).

Each Merchant Function Charge would include uncollectibles associated with the commodity, gas supply procurement costs, and records and collections costs. The Merchant Function Charge will also include projected monthly quantities and prices of Corning's balances of gas in storage for the rate year and each 12-month period thereafter. Most of the storage asset is used to serve firm sales customers, but a portion of the asset is used to balance the system, benefiting all customers. Thus, 80% of the storage inventory component would be charged to firm sales customers via the MFC, with 20% charged to all customers.

The joint proposal would direct Corning to file a report by August 5, 2010, on the feasibility of Corning conducting a study regarding the purchase of receivables from energy services companies operating in the Corning service area. A report on the feasibility of a POR study would be required annually thereafter until a study is completed. Corning is to file future embedded cost studies in conformance with the Commission's Statement of Policy on Unbundling.

FERC Orders Refunds for 2008-09 Period in Pepco Energy Services' Availability Charge Complaint

FERC granted a complaint from Pepco Energy Services regarding peak-hour-period availability charges under PJM's Reliability Pricing Model, ordering refunds for the delivery year 2008-2009, but not for 2007-2008 (EL08-58, Matters, 4/23/08).

During the period of the complaint, peak availability charges or credits were generally based on a generator's Equivalent Forced Outage Rate during the approximately 500 hours that comprise the Peak-Hour Periods (EFORp). However, for an infrequently-run generator that has fewer than 50 total Service Hours during Peak Hours, the charges or credits were not based on the EFORp but were instead based on the resource's actual Equivalent Demand Forced Outage Rate (EFORd) for all 8,760 hours during the applicable Delivery Year.

Pepco Energy Services complained that such a mechanism penalized infrequently run units for outages which did not occur during peak periods. FERC agreed, noting that even if an infrequently run unit meets the peak hour availability target, it may be penalized for outages at other times if it fails to run for 50 hours.

FERC found that refunds for the 2007-08 delivery year could not be granted as the complaint was filed after the peak period for that year. Refunds will be required for the 2008-09 delivery year, with charges recalculated using a new method of assessing availability charges adopted in March 2009. Under the new methodology, the peak-hour-availability measure of an infrequently run resource shall be the lower of the resource's EFORd (based on the delivery year outage data) or the resource's EFORp.

Briefly:

DPUC to Conduct Lessons Learned Review of Mechanics of Standard Service Procurement

The Connecticut DPUC opened docket 06-01-08RE04 for a "lessons learned" review of the full requirements Standard Service procurement process. The scope is explicitly limited to the mechanical aspects of the solicitation and procurement of full requirements service contracts by the electric distribution companies. Issues associated with long-term individual bilateral standard service contracts will not be considered, nor will issues associated with procurement disclosure.

Mass. Pursues Statewide Solar Pool

A new Massachusetts statewide entity is to be created with the intent of jointly developing large scale solar photovoltaic installations with Nstar, National Grid, Fitchburg Gas & Electric, and Western Massachusetts Electric Company, as part of reaching the state's goal of 250 MW of solar by 2017. The statewide pool approach was announced by Gov. Deval Patrick and Attorney General Martha Coakley, but the exact interaction with utilities is still subject to negotiations. The pool approach was first reported by *Matters* as a condition of a settlement between the Attorney General and WMECO regarding WMECO's petition to build 50 MW of utility solar (Matters, 7/1/09). Under the statewide pool, competitive solicitations would be used to procure up to 25 MW of solar capacity at a time, with procurements limited to large scale (100 kW or above) projects. The pool approach is subject to DPU approval.

Maine PUC Draft Would Approve BHE Incremental Advanced Metering Plan

The Maine PUC would approve the installation of advanced metering infrastructure at Bangor Hydro-Electric consistent with an incremental smart grid proposal subject to the receipt of Department of Energy stimulus funds, under a draft order issued yesterday. The receipt of a 50% DOE grant would likely make smart grid installation for BHE cost beneficial, the draft order found.

FERC Clears Way for MidAmerican to Join MISO

FERC accepted a series of filings that will permit MidAmerican Energy join the Midwest ISO, including filings related to financial transmission rights, local transmission planning, existing agreements for transmission service, and MidAmerican's transmission revenue requirement. The Commission also concluded that the formerly effective restrictions on the MidAmerican companies' market-based rate authority may be removed upon MidAmerican's integration with the Midwest ISO.

FERC Denies Boralex's Grandfathered Transmission Complaint

FERC denied a complaint from Boralex Ashland against ISO New England regarding a grandfathered transmission service agreement, finding that Boralex's grandfathered agreement does not entitle Boralex to any ICAP import rights over the New Brunswick interface into the ISO-NE market (EL09-51). Boralex's grandfathered agreement provides it with scheduling and curtailment priority over non-firm transmission users over the MEPCO facilities, but it must apply to ISO-NE under a separate agreement to import ICAP on a first-come, first-served basis, FERC held. Boralex had claimed that the agreement entitled it to priority in both energy and capacity imports (Matters, 5/12/09).

Mich. PSC Directs Edison to Follow Deskewing in Self- Implemented Rates

If Detroit Edison chooses to self-implement an interim rate increase while the Commission considers its rate case (as Edison intends to do), the Michigan PSC said that the interim increase shall be allocated to rate classes in the same manner as in Edison's January rate proposal; that is, commercial and industrial rates will begin to be deskewed. While legislation contemplates that any interim rate increases are to be applied using an equal percentage across all rate classes, the Commission, as it recently did at Consumers Energy, found that such equal, across the board increases would frustrate efforts to end the residential subsidy within five years. Adopting a recommendation from Constellation NewEnergy, the Commission directed Edison to serve upon all parties a notice contemporaneous with its receipt from the Staff of the stamped and effective tariff that specifies the self-implemented rates should be granted. Constellation had noted confusion regarding the in-effect tariff at Consumers following self-implementation of a rate increase there. The PSC said a reduction in the power supply cost recovery (PSCR) factor starting August 1 will offset the rate hike, lowering the increase in the average residential customer's monthly bill to $1.66 (2.7 percent).

Comverge Selected for Pa. Demand Response Pilot

Comverge said it has entered into a partnership with the Pennsylvania Department of General Services to service a demand response pilot program being conducted by the state for four government buildings. Selected through competitive bidding, Comverge said it will provide a turnkey implementation program for demand response services including load curtailment opportunity identification, program education, registration, notification, compliance, settlement functions and, where applicable, metering and integration within PJM.

FERC Revokes PowerGrid Systems MBR Authority

FERC revoked the market-based rate authority of PowerGrid Systems, Inc. for failure to file Electric Quarterly Reports.

FERC Smart Grid Policy Statement Permits Single Issue Ratemaking

FERC issued a smart grid policy statement yesterday that allows for single issue rate treatment for the recovery of smart grid costs, and does not require any cost-benefit analysis for investments (PL09-4). Utilities will be required to meet several conditions to qualify for rate approval of smart grid costs, including a showing that the applicant has minimized the possibility of stranded investment in smart grid equipment, in light of the fact deployments will predate adoption of interoperability standards. FERC said that it is important to develop standards that support dynamic pricing, but noted its jurisdictional limits and stressed that it is not FERC's intention to require the use of dynamic pricing in retail rates.

CPV ... from 1

agreement if its declaratory ruling is granted.

Thus, Panda-Brandywine argued, the future of the CPV facility is in doubt if the County does not obtain a favorable court ruling. The hearing date for motions and cross-motions for summary judgment in the federal court action is not until September 29, 2009. The court will not decide whether to grant the County's requested declarations until then, at the earliest, Panda-Brandywine said. Yet CPV has asked the PSC to award it long-term SOS supply contracts no later than September 4, 2009, Panda-Brandywine noted.

The County's statements as to the necessity of the declaratory ruling to meet the terms of both agreements, "raise[s] substantial doubts about the CPV's [sic] ability to secure a treated effluent cooling water source in amounts sufficient to cool the proposed power plant should the County fail to prevail in the federal court action. These doubts, in turn, inexorably lead to questions about CPV's ability to reliably perform under a power sales agreement with an investor-owned utility," Panda-Brandywine said.

Order 719A ... from 1

719 grants retail authorities the ability to judge retail customer participation on a case-by-case basis, since the order recognizes that the laws of a retail authority may not permit "**a** retail customer to participate" [emphasis supplied].

In Order 719-A, FERC does not address the issue specifically. FERC does say, however, that its original rule, "did not challenge the role of states and others to decide the eligibility of retail customers to provide demand response."

"[W]e leave it to the relevant retail authority to decide the eligibility of retail **customers**," FERC added [emphasis supplied].

"The Final Rule also does not make findings about retail customers' eligibility, under state or local laws, to bid demand response into the organized markets, either independently or through an ARC [aggregator of retail customers]. The Commission also does not intend to make findings as to whether ARCs may do business under state or local laws, or whether ARCs' contracts with their retail customers are subject to state and local law. Nothing in the Final Rule authorizes a retail customer to violate existing state laws or regulations or contract rights. In that regard, we leave it to the appropriate state or local authorities to set and enforce their own requirements," the Commission says in Order 719-A.

Order 719-A does carve-out an exception intended to ease burdens on smaller utilities with loads less than 4 million MWh annually. RTOs must presume that customers at such small utilities are prohibited from participating in RTO demand response programs unless the relevant retail authority provides affirmative notification to the RTO that customers may participate. Specifically, FERC's new language holds:

"We direct RTOs and ISOs to amend their market rules as necessary to accept bids from

ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC. RTOs and ISOs may not accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an ARC, or (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC."

FERC denied rehearing on most other aspects of the order, including shortage pricing and market monitoring and tariff mitigation roles. The Commission did clarify that a market monitor will be allowed to perform independent monitoring of an entity other than the RTO or ISO it monitors, whether or not such entity is a participant in the RTO or ISO markets, but only where such monitoring is directed by a Commission order.