Energy Choice Matters

December 31, 2009

BGE Seeks to Collect Additional SOS Working Capital Through Nonbypassable Charge

Baltimore Gas and Electric petitioned the Maryland PSC to allow it to recover an increase in SOS cash working capital requirements associated with PJM's implementation of weekly billing, through the nonbypassable Administrative Cost Adjustment.

BGE reported that with the implementation of PJM weekly billing on June 1, 2009, BGE has experienced a material increase in its SOS-related cash working capital (CWC) revenue requirement that precludes the company's ability to "provide standard offer service [...] at a market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return."

BGE's SOS-related cash working capital revenue requirement represents the cost of the permanent level of capital the company must obtain in order to finance the working capital necessary to provide BGE customers with SOS-related services. In simple terms, the cash working capital revenue requirement represents BGE's cost of carrying substantial SOS-related purchases, which are now payable weekly, while waiting for the receipt of cash from its customer billings which takes 38-45 days from when the SOS service is initially rendered.

The existing mechanism for recovery of cash working capital costs was established in the Case 8908 SOS Settlement Agreements, which limit the ability of the utilities to fully recover the costs associated with non-residential SOS-related cash working capital. Specifically, the Settlement

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Tres Amigas Project May Raise Rates for Texans, Destroy Value of CREZ Investment, Industrials Say

Tres Amigas' application to build a superstation connecting ERCOT, the Eastern Interconnect and Western Interconnect has the potential to increase power prices across ERCOT and the Texas portions of the Southwest Power Pool, while also making Texans pay for transmission to export power to other markets, the Texas Industrial Energy Consumers said in a protest at FERC.

As was first reported by *Matters*, Tres Amigas has sought FERC authorization to sell transmission services at negotiated rates (ER10-396, First in Matters, 12/9/09). Tres Amigas is also seeking a waiver of FERC jurisdiction over ERCOT connections to its project. While interrelated, TIEC's comments were specifically addressed at the petition for negotiated rate authority.

TIEC noted that Tres Amigas asserts that its proposed project would equalize market prices for energy among the areas that the project will interconnect. "However, equalized electricity prices will not benefit lower-cost markets, which include the two Texas markets identified in Tres Amigas' application," TIEC noted. Given the lower prices in ERCOT and SPP relative to CAISO and ICE, "equalizing electricity prices across the grid would likely occur at the expense of Texas customers who would see their energy prices rise as lower-cost power is exported to higher-cost markets," TIEC argued.

"[T]he Tres Amigas project could cause significant harm to consumers in Texas," as lower-cost power is exported, TIEC added.

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Pa. PUC Staff Calls Omissions in UGI POR Discount Rate Inconsistent with Guidelines

The Pennsylvania PUC's natural gas purchase of receivables guidelines, "clearly indicate that ... implementation costs should be recovered from the [supplier] through a discount rate," the PUC's Office of Trial Staff said in recommending that a petition for a POR program by UGI Utilities - Gas Division be assigned to an ALJ.

As only reported in *Matters*, UGI has proposed recovering $800,000 in development costs through a nonbypassable rider applicable to all customers, rather than through the discount rate, because including such costs in the discount rate would make it prohibitively high. Ongoing administrative costs, as well as uncollectibles, are to be included in the proposed discount rate (Only in Matters, 12/7/09).

Staff said that such a proposed cost recovery for development costs is inconsistent with the PUC's directives in the interim POR guidelines (M-2008-2068982).

Additionally, Staff said that the discount rate excludes certain essential items, though Staff was not specific on such items aside from citing development costs.

Staff further said that UGI's proposed changes to the Price to Compare, to include supply-related uncollectibles, is not revenue neutral as there is not an appropriate removal of Supplier Of Last Resort costs from base distribution rates.

Direct Energy generally supported UGI's petition. Direct said that it is willing, at this time, to agree with UGI's proposed class-specific all-in approach, whereby participating suppliers must use UGI's consolidated billing for all of their customers within a customer class in the POR program.

"Direct prefers an approach that provides participating suppliers with the flexibility to use POR with utility consolidated billing and/or dual billing and/or competitive supplier consolidated billing within the same customer class," Direct said. Direct requested that within one year after the POR program commences, UGI should be required to review the all-in approach via a collaborative process with the goal of transitioning to a more flexible billing options environment.

Although not clearly defined in UGI's proposal, Direct supports the ability of a competitive supplier to offer other commodity-based offerings through UGI's consolidated billing with POR, such as a carbon neutral product. Direct does not support, at this time, the billing of energy efficiency products or services through UGI's consolidated billing with POR program.

Columbia Reaches Compromise on Pipeline Scheduling Point Definition for Ohio Tariff

Columbia Gas of Ohio, in filing tariff revisions reflecting its approved Standard Service Offer auction procurement methodology, has revised the definition of "Pipeline Scheduling Point" included in the tariff.

Columbia said that parties in the case have agreed to the revised, compromise definition in return for Columbia Gas of Ohio's willingness to make a written commitment that, if Columbia Gas Transmission, LLC alters its definitions of "Market Areas" or "Master List of Interconnections" in any way from the specific points in its tariff, Columbia Gas of Ohio will meet with all interested parties, including suppliers, customers, the Office of the Consumers' Counsel and PUCO Staff, to discuss how to minimize the impact of the Columbia Gas Transmission changes on Columbia's system and its customers.

The revised tariff defines "Pipeline Scheduling Point" as a single delivery point or set of delivery points grouped or designated by an upstream pipeline for purposes of scheduling gas supplies for delivery by such upstream pipeline, consisting of the following: interconnections with Panhandle Eastern Pipe Line Company, Tennessee Gas Pipeline, North Coast Gas Transmission, LLC, and Columbia Gas Transmission, LLC. The interconnections with Columbia Gas Transmission, LLC include the Market Areas and Master List of interconnections as defined in the General Terms and Conditions of the FERC Gas Tariff of Columbia Gas Transmission, LLC. As of December 2, 2009, the Columbia Gas

Transmission, LLC Pipeline Scheduling Points included: 22 (Portsmouth); 23-1 (Toledo); 23-3 (Lima); 23-4 (Alliance); 23-5 (Columbus); 23-6 (Dayton); 23-8 (Mansfield); 23-9 (Ohio Misc.); 23N-2 (Parma); 23N-7 (Sandusky); 24-35 (Pittsburgh); and 24-39 (New Castle).

The prior definition did not cite specific interconnections or points.

FERC Suspends Revised Allocation for CAISO Market Usage-Forward Energy Charge

FERC accepted for filing, but suspended subject to refund, the California ISO's petition to apply the Market Usage-Forward Energy (MU-FE) charge based on the "greater of" supply or demand in the day-ahead schedules of market participants, as the Commission established hearing and settlement judge procedures on the petition (ER10-188).

Currently, the MU-FE charge is based on the net activity of a market participant, and the ISO believes that a gross approach, where demand and supply schedules are not netted against each other, would be a more appropriate approach based on cost causation.

However, the ISO is concerned that applying the charge to gross energy schedules would result in substantial cost impacts to certain market participants, and thus instead proposed that the MU-FE charge be based on the "greater of" a market participant's supply or demand in the day-ahead schedules. Incumbent LSEs which self-schedule generation to meet supply would be among the market participants seeing higher charges under a gross approach (Only in Matters, 11/23/09).

FERC said that the CAISO's filing raises issues of material fact, "regarding whether the proposed Market Usage-Forward Energy charge and its formula for determining rates and allocation is actually based on cost causation by the individual market participants subject to the charge." FERC noted that the CAISO has not provided a cost-of-service study demonstrating that its modified gross approach to determine the Market Usage-Forward Energy Charge is based on cost causation principles. Further, the CAISO has failed to provide any evidence regarding cost impacts even though it contends that those impacts are taken into account in the proposed calculation, FERC said.

"Moreover, the CAISO claims that allocating the Market Usage-Forward Energy Charge using a gross approach more appropriately reflects cost causation. Despite this conclusion, the CAISO proposes using a modified gross approach because such an approach would limit the cost impacts to certain market participants. However, such a basis may not be appropriate for any component of the Grid Management Charge, as all components are to be based on costs incurred by the CAISO for providing certain services to market participants," the Commission added.

The Commission also accepted the CAISO's proposed tariff revision to extend the current Grid Management Charge, with the $197 million revenue requirement cap, until December 31, 2010. This aspect of the petition was unopposed.

Briefly:

Detroit Edison Reports Preliminary 2010 Choice Cap

Detroit Edison said that its 2010 Preliminary Customer Choice Cap is 4,559,572 MWh, reflecting weather-adjusted actual sales through November and a forecast for December (U-16088). Current choice sales at Detroit Edison are 4,930,608 MWh, which already exceeds the 2009 cap of 4,928,521 MWh. Thus, based on the preliminary 2010 cap, there is no room to accommodate the 380,494 MWh in Detroit Edison's queue waiting for space under the cap, absent any customer returns to bundled service. Under the Michigan rules for the choice cap, customers currently taking retail access service will not be forced off of competitive supply even though the projected 2010 cap is less than the current level of retail access sales. A final cap, reflecting actual sales for all of 2009, will be filed by February 1.

Md. PSC Revives EDI Working Group

The Maryland PSC issued a notice re-establishing the Electronic Data Interchange Work Group for the purpose of addressing EDI transaction standards and procedures in support of the recently adopted COMAR 20.53 regulations, including the provision for purchase of receivables. The Commission directed its Technical Staff to facilitate the Work Group. The Work Group should be composed of stakeholders from electric utilities, electric suppliers, Office of People's Counsel, and other customer groups' representatives that wish to participate in the Work Group, the Commission said. The Work Group also may wish to address EDI housekeeping issues and consistency with regional standards and procedures, as needed, the PSC added. Staff shall file any suggested revisions to the existing standards with the Commission for administrative approval.

TransCanada Pipelines Seeks Ontario Electric Wholesaler Licence

TransCanada Pipelines Limited has applied to the Ontario Energy Board for an electricity wholesaler licence.

BGE ... from 1

Agreements limit the recovery of non-residential cash working capital costs to the lower of one-half of the cash working capital revenue requirement, or $0.15/MWh.

BGE reported that its recovery of cash working capital costs prior to June 1, 2009 was $.06/MWh, compared to a revenue requirement of $0.12/MWh. As a result of the June 1, 2009 change from monthly to weekly PJM settlement, BGE's cash working capital revenue requirement is now $1.10/MWh, over 600% higher than the current cost recovery which has been limited to the $0.15/MWh cap.

BGE proposed to modify its Type I, Type II, and Hourly SOS cost recovery mechanism to provide for the recovery, on a pass-through basis, of the verifiable, prudently incurred costs of providing the service, adjusted every four months. BGE did not request any change related to residential SOS.

BGE proposed that its full cash working capital revenue requirement shall be recovered as an SOS-related cost through Rider 10 (Administrative Cost Adjustment), a nonbypassable charge. "Utilizing Rider 10 to address the recovery of BGE's CWC costs will not increase the SOS price for non-residential customers," BGE noted. Though BGE did not provide specific allocation of the cash working capital through Rider 10, the rider is currently a class specific charge for each SOS class-type. Additionally, while BGE said it is only seeking to recover the increase in non-residential cash working capital requirements, it did not say whether residential customers would be excluded from the recovery under Rider 10.

BGE said that modification to the revenue requirement cap in the Case 8908 Settlement Agreement is warranted since parties did not contemplate PJM would move to weekly billing in that stipulation. BGE further noted that, under the Settlement Agreement, the SOS service period for Type I customers expired on June 1, 2008 and the SOS service period for Type II customers expired on June 1, 2006. "An adjustment to BGE's SOS cost recovery mechanism to address the change in the PJM settlement structure is justified since the parties to the Case No. 8908 SOS Settlements did not contemplate SOS service periods for BGE's non-residential customers to continue past the agreed-upon service periods," BGE said.

Tres Amigas ... from 1

Furthermore, TIEC said that the Tres Amigas project would "undermine" the Texas Competitive Renewable Energy Zone initiative, under which ERCOT ratepayers are funding transmission under the justification that the lines will access low cost wind power to lower prices in the ERCOT market.

If the CREZ lines are underutilized as a result of the Tres Amigas project, or used to export power out of state, "then the Texas legislature's intent and the basis of the PUCT's decision will be undermined and Texas consumers will be harmed," TIEC contended.

TIEC noted that PUCT approval for $5 billion in CREZ investment was predicated on the finding that the investment would provide an average savings of $38/MWh for each megawatt-hour of wind.

TIEC reported that to justify the CREZ CCNs, Texas regulators are reviewing and could rely upon some of the same renewable projects that Tres Amigas now cites as projects that will interconnect to Tres Amigas' facility. The PUCT is required to evaluate the level of financial commitment from renewable energy generators in various CREZs before issuing CCNs for lines in those areas, an evaluation which is currently ongoing.

However, TIEC noted that one of the wind generators that submitted proof of commitment in PUCT docket 37567 was Scandia Wind Southwest, LLC -- the same company responsible for the 5 GW Mariah wind project referenced in Tres Amigas' application. Tres Amigas, TIEC observed, uses Scandia Wind as an example of a wind generator that seeks to interconnect to the Tres Amigas facility, with Tres Amigas attaching a letter of support from Scandia to its application for negotiated rates.

"Meanwhile, the very same Scandia project is being relied upon by the PUCT to justify the massive CREZ transmission investment. Thus there is already some evidence that Texas customers may lose the benefits of their investment in CREZ transmission as a result of the Tres Amigas project," TIEC said.

Furthermore, TIEC noted that Tres Amigas' proposal would also create the largest single contingency within ERCOT, as it is seeking the ability to transmit up to 5,000 MW into the ERCOT region initially, with expansion plans up to 30,000 MW. Currently, the single largest contingency in ERCOT is 2,300 MW, or the loss of two nuclear units.

Texas Amigas' level of contingency, "raises serious potential reliability issues, the possibility of increased ancillary service requirements, and potential cost increases for ERCOT customers," TIEC cautioned.

"These contingencies are particularly troublesome given the limited transmission access to the significant load centers in ERCOT, and the potential swings in power between the different markets," TIEC said.

TIEC argued that FERC must conduct a hearing to determine whether Tres Amigas will have market power, since it would be the sole provider of transmission services connecting the three interconnects. Other merchant projects receiving negotiated rate authority from FERC have faced competition from incumbent, cost-regulated lines, TIEC noted.

Occidental Power Marketing also protested Tres Amigas' application on market power concerns. The fact that Tres Amigas likens itself to a "new power marketing hub" rather than a traditional transmission line, and, "boasts that 'no one has ever offered these particular services' before," means Tres Amigas is proposing, "nothing short of the creation of an entirely new market - the market for energy transfers and sales among and between all three asynchronous interconnections," Occidental said. Moreover, Tres Amigas has not shown that there will be any other participant in that new market, Occidental added.

Citing the potential expansion of the Tres Amigas project from 5 GW to 30 GW, Occidental asks, "what is to keep Tres Amigas from building from its existing infrastructure and expanding the size of its facility to capture any market headroom that does exist before a would-be competitor has time to construct its own facilities?"

"Indeed, the mere threat of expansion could deter competitors, particularly since expansion of an existing facility for which a site already exists is often less costly and quicker to construct than an entirely new facility. In fact, that appears to be part of the plan, as the December 8 Filing states it is 'committing to expand Tres Amigas to satisfy demand,'" Occidental adds.

"Further, the holdback of up to 20 percent of its transmission capacity for short-term sales coupled with its plan to sell firming energy and ancillary services may well give Tres Amigas the incentive and ability to raise transmission rates during periods of supply scarcity in any of the interconnections. By selling transmission services during short-term periods of scarcity, it may be able to obtain very high transmission rates (approaching the difference in price between suppliers in interconnections that are not facing scarcity and scarcity pricing in high-cost zones). The result may be very high transmission rates and possibly high energy rates for Tres Amigas but little relief from high energy prices in the interconnection confronting scarcity of supply," Occidental added.

Golden Spread Electric Cooperative also stated that, given the potential renewable energy generation in the region where Tres Amigas is proposed, and federal policies potentially increasing reliance on such renewables, "[t]he last thing that should be allowed is creation of a 'choke point' where an unregulated toll-keeper controls the economics of these power flows."