Energy Choice Matters

June 18, 2010

Pa. PUC Rejects Mandating Minimum Credit Rating as Adequate Security

The Pennsylvania PUC declined to adopt a mandatory requirement that natural gas distribution companies (NGDCs) shall permit natural gas suppliers (NGS) to meet the applicable security requirement through use of a minimum investment grade credit rating or its equivalent, in a final rulemaking order published yesterday (L-2008-2069115 et. al.). As previously noted, the final gas supplier security regulations maintain the ability of suppliers to use receivables purchased by the LDC as a form of security (see Matters, 6/17/10).

"While we agree that a NGS's credit rating may be taken into account by an NGDC in establishing the amount of security, we cannot adopt [the Retail Energy Supply Association's] proposal to eliminate the security requirement upon the showing of some baseline creditworthiness standard. Risks vary from supplier to supplier, and thus, financial exposure posed by suppliers operating on NGDC systems vary from NGDC to NGDC making a baseline creditworthiness standard based solely on credit or investment ratings difficult, if not impossible, to establish for use in the statewide retail market," the PUC said.

However, the Commission noted that some LDCs do not require a supplier to post additional security when the supplier has a high credit rating, or is backed by a highly rated parental or other corporate guaranty. "To the extent that a NGDC has adopted such a standard, we will direct that the NGDC include this standard in its tariff. This will ensure that all NGSs have notice of the standard and will further ensure that the standard is applied in a non-discriminatory manner to all NGSs," the PUC added.

The Commission also declined RESA's suggestion to use a standardized formula to calculate the

Continued P. 6

N.Y. PSC Adopts Three-Year Rate Plans for Central Hudson Gas, Electric Service

The New York PSC approved a three-year rate plan for Central Hudson Gas & Electric for both electric and gas delivery largely based on a joint proposal filed in February (09-E-0588 et. al.). A written order was not available.

As only reported in *Matters*, under the joint proposal several costs are to be removed from Central Hudson's electric and gas Merchant Function Charge (MFC) Supply Charge, and placed in the MFC Administration Charge, while some costs would be removed from the MFC Administration Charge and placed into base rates.

Regardless of commodity, a full service customer is charged both the MFC Administration rate and MFC Supply rate. A retail access customer billed on utility consolidated billing is charged the MFC Administration rate but avoids the MFC Supply rate. A retail access customer on dual billing avoids both the MFC Administration rate and MFC Supply rate.

Under the joint proposal, all costs recovered under the current MFC Administration Charge are to be moved to base rates. Such costs include delivery-related credit and collections costs and delivery-related uncollectibles.

Continued P. 7

Pepco, Delmarva File Updated Type II SOS Rates

Pepco and Delmarva filed Type II SOS generation rates with the Maryland PSC for the quarter beginning September 1.

Pepco	**Generation Service Charge**
MGT LV II	(9/1/10-11/30/10)
On Peak	8.148¢/kWh
Intermediate	8.148¢/kWh
Off Peak	8.148¢/kWh
MGT 3A II	
On Peak	8.035¢/kWh
Intermediate	8.035¢/kWh
Off Peak	8.035¢/kWh

Delmarva	**Energy Rate** (9/1/10-11/30/10)
SGS-S	7.6450¢/kWh
LGS-S, GS-P	
On Peak	7.6450¢/kWh
Off Peak	7.6450¢/kWh

Many PPL Customers Don't Want to Leave PPL

A significant portion of residential customers at PPL Electric Utilities say they don't want to leave PPL, a survey by PPL found. Some 41% of survey respondents had switched suppliers (versus the actual residential migration rate of about 30%)

In the online survey of 360 residential customers, conducted in May, some 40% of customers said that they have not done any shopping around (e.g. comparisons) for a competitive supplier. Of this amount, 41% said that the reason was that they did not wish to leave PPL (or 16% of total respondents, with the caveat that the survey sample had a higher percent of respondents who have switched than the overall service area).

Of those who have not done any shopping, other reasons for not shopping were:

- Price differential not significant enough: 26%
- Too confusing, don't want to be bothered by it: 23%
- Concerned my electric service will not be as reliable: 23%
- Don't know the new suppliers: 22%
- Not enough information to shop: 19%
- Not enough time to shop: 15%

Of those customers who have shopped around, nearly 70% ended up switching to an alternative supplier rather than remaining with PPL. For those customers who had switched suppliers, the majority selected their supplier based on price (58%). Other reasons for selecting a particular supplier were:

- No contract term/exit fee: 21%
- Ease of understanding supplier's offer: 6%
- Supplier's advertisement/special offer: 4%
- Company reputation: 3%

More than half of customers who have switched say that they have recommended their supplier to someone else.

In the aggregate, PPL said that nearly two-thirds of volume is served by competitive suppliers. Competitive suppliers serve 445,000 of PPL's approximately 1.4 million customers. Residential migration is 376,600 customers (about 30%).

Briefly:

Ambit Energy Seeks Md. Electric, Gas Licenses

Ambit Energy has applied for both electric and natural gas supplier licenses in Maryland to serve residential and commercial customers in all service areas. Ambit focuses on the residential market.

Freedom Logistics Seeks Conn. Aggregation License

Freedom Logistics, LLC applied for a Connecticut electric aggregator certificate to serve non-residential customers. Freedom has specialized in facilitating direct end user procurement of power at wholesale (with such entities often self-supplying themselves at retail), but said that it believes now is the time to expand into procurement services for medium and small commercial customers, and large customers unwilling to go through the steps needed to buy at wholesale. Freedom initially only plans to accept referral business and will not conduct any marketing or cold calling.

Hess Wins New Jersey GSA Gas Contract

Hess Energy Marketing has been awarded a three-year contract with the General Services Administration to provide natural gas for nine New Jersey facilities, totaling approximately 1,550,000 therms. The contract was brokered by World Energy via reverse auction. Hess is currently supplying natural gas to these GSA facilities through a previously awarded two-year contract that is set to expire later this summer.

World Energy Solutions Brokers 450 GWh in Pa. in Six Weeks

World Energy Solutions, Inc. said that it has brokered over 450 million kWh of electricity for Pennsylvania customers in the last six weeks. World Energy said that its experience in brokering Pennsylvania load is "similar" to its experience in Ohio last year where it said it brokered nearly 10% of competitive supply at the FirstEnergy utilities and Duke Energy Ohio. Unsurprisingly, World Energy said that it saw the strongest activity at PECO, but with healthy activity also reported at Met-Ed, Penelec, West Penn Power, Duquesne and PPL as well. World Energy is using several channel partners in its Pennsylvania efforts, including APPI, Applied Energy, Commercial Utility Consultants, EnergyWise Consulting and Practical Energy.

FERC Denies Request for NYISO Forecast of Highway Charges

Dismissing the concerns of load serving entities, FERC approved as filed the New York ISO's compliance filing to establish a funding mechanism to recover, from load-serving entities, the cost of so-called "highway" transmission upgrades that are constructed by transmission owners (ER04-449).

The new Highway Facility Charge does not establish a set rate, but rather creates a mechanism to allow for the monthly collection of highway transmission project costs from load serving entities using several inputs, with the charge potentially varying on a monthly basis.

ConEdison Solutions had expressed concern that the proposed tariff revisions do not specify a timetable that the NYISO must follow to identify and post Highway Facility Charges. ConEdison Solutions said that the Highway Facilities Charge should remain at a steady predictable rate, comparable to other transmission charges, so that upgrade costs can be included in ESCOs' contracts with their retail customers.

When structured as a monthly allocation, there is the potential for Highway Facility Charges to increase dramatically month to month without any advanced notice, ConEdison Solutions noted. Such monthly fluctuations are harmful to retail suppliers because retail suppliers are unable to defer unanticipated charges and typically do not have the ability to simply pass the Highway Facility Charge cost through to their customers, but instead must predict such costs and include them in their retail contract prices.

ConEdison Solutions requested that, if the Highway Facility Charge were to change monthly, the NYISO should post both the current rate as well as a forecast of future rates, based on approved projects, so that ESCOs can incorporate the Highway Facility Charge costs into their retail prices. ConEdison Solutions noted that the NYISO is uniquely positioned to track the transmission projects, forecast the anticipated Rate Schedule 12 charges, and convert them into a posted schedule of rates on a kW-month basis for ESCOs.

FERC denied this request, claiming that "load-serving entities should have access to all the same information available to NYISO that they can use to try to forecast their own monthly cost allocation for Highway System Deliverability Upgrades."

"The procedural requirements embedded in this mechanism by which the transmission owner will make two separate filings with the Commission will provide load serving entities with advance information from which to make their own estimates of applicable monthly Highway Facilities Charges allocations," FERC said.

FERC Seeks to Socialize More Transmission Costs, End Right of First Refusal

In a proposed rule that would further add to the burden of retail end users, FERC has tentatively called for greater cost socialization in transmission cost allocation, and also proposed striking the federal right of first refusal from a transmission owner's OATT, endangering participation in, and thus the span of, organized markets (RM10-23).

FERC claimed that the changes in transmission planning and cost allocation are needed due to recent industry changes, despite the recent issuance of Order 890 which addressed many of the same issues.

Chief among the provisions of the NOPR is the elimination of a federal right of first refusal for the construction of transmission projects contained in a regional plan by the incumbent provider for that transmission zone. FERC claimed that this federal policy was unduly discriminatory. FERC claimed that its proposed rule would not infringe on any state laws providing a right of first refusal.

Several stakeholders noted that the federal right of first refusal has provided an incentive for transmission owners to join RTOs, expanding the scope of organized markets.

"Efforts by some to challenge this right of first refusal, or perhaps better stated, right of first opportunity, of the Transmission Owners to build new transmission are not only contractually unsupportable but in fact threaten the foundation upon which the Midwest ISO was established," the Midwest ISO Transmission Owners had noted.

"Eliminating the first opportunity to invest ... would provide a disincentive to new members considering joining an RTO and could even encourage existing Transmission Owners to depart," the MISO Transmission Owners added.

Although the federal right of first refusal would also be removed from non-RTO OATTs, prompting Chairman Jon Wellinghoff to claim that RTO exits are a non-issue, the California ISO noted that if transmission owners were not members of an ISO or RTO, they could build new transmission projects to serve their load by simply obtaining a certificate of public convenience and necessity from their state regulatory commission or applicable local regulatory authority, and not through a regional plan. "Thus, the absence of a right of first refusal mechanism would serve as an inappropriate and potentially significant disincentive for such transmission owners to join ISOs and RTOs," CAISO noted.

Although proponents for eliminating the right of first refusal cite the exclusion of lower-cost projects due to the incumbent's priority, CAISO noted that such arguments are speculative. "With respect to cost issues, there is no way to guarantee that the submitted project that has the lowest cost estimate at the time it is submitted will actually turn out to be the cheapest project. Project sponsors could simply submit 'low-ball' cost estimates for the sole purpose of getting their projects approved, and even if actual construction costs end up being significantly higher, the ISO or RTO will have little ability (or flexibility) to approve a competing project at that point," CAISO said.

Planning and Cost Allocation

FERC's NOPR greatly expands the transmission planning process, and thus potential projects built under the process's cost allocation mechanism, to include "consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs." The NOPR does not attempt to define such public policy considerations, which are left to the transmission provider after consultation with stakeholders.

Additionally, after consulting with stakeholders, a transmission provider may include in the transmission planning process additional public policy objectives that are not specifically required by state or federal laws or regulation.

FERC said that by considering "public policy" goals in the transmission planning process, the planning process can reduce, "the proportion of network upgrades that would otherwise be triggered by individual generator interconnection requests." Such network upgrades, though subject to some cost sharing depending on region, typically assign a large portion of costs to the party requiring the upgrade, rather than burdening end users with the cost of interconnecting generation which has elected to be sited in either a congested or remote area. FERC's NOPR is designed to result in more socialization of these costs.

Apart from expanding eligible projects, the Commission has also ordered reforms to transmission cost allocation formulas to increase cost socialization, prescribing a set of principles that transmission providers must follow. While each transmission provider may develop its own cost allocation formula in response to these principles, FERC retains authority to usurp the product of the stakeholder process if FERC deems the result to be inconsistent with FERC's dictates.

To begin, FERC has effectively banned the participant-funded approach to cost allocation, except where voluntary. In other words, FERC's principles require that, if any party in the transmission-planning region "benefits" from the transmission project, and the project's sponsor requests and receives inclusion in the regional transmission plan, the claimed beneficiaries must be allocated some of the costs.

"A cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission described in Order No. 890. Such a cost allocation method would not satisfy the proposed principles," FERC said.

While the principles also hold that "[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities," this proposed end user protection is toothless given FERC precedent. Specifically, FERC has essentially deemed all high-voltage transmission (345 kV or higher) to provide reliability benefits to an entire region, regardless of current power flows, since, "benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments."

While a federal court has remanded FERC's justification of cost socialization on these grounds, FERC noted that it need only show that users who have been assigned costs of transmission projects are assigned costs, "at least *roughly* commensurate with the benefits that are expected to accrue to that entity" [emphases added]. As FERC said that it is empowered to ignore "exacting precision" in favor of this rough cost allocation, it seems transmission customers will be unable to escape cost socialization of the massive build-out of transmission FERC hopes to subsidize under its proposed rule, regardless of their actual benefits from remote high voltage transmission.

Furthermore, the imposition of transmission costs on end users will be further expanded as FERC will allow cost allocation decisions to consider the claimed "public policy" benefits transmission customers receive from the transmission line. As these public policy benefits are not defined by FERC, it's unclear whether transmission customers in states which have successfully met their RPS goals with in-state or nearby renewable facilities will be saddled with the cost to access remote generation to meet broad public policy goals or those of other states in the same transmission planning region, on the argument that customers in the states with no need for new renewables still derive some ethereal societal benefit from additional renewable generation despite meeting their own internal RPS targets.

The NOPR provides that, "[i]n determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs."

FERC Briefs:

FERC Approves SPP Highway/Byway Cost Allocation

FERC approved the Southwest Power Pool's "Highway/Byway" transmission cost allocation mechanism under which, for facilities at or above 300 kV, 100% of costs are socialized across the SPP region. For facilities above 100 kV and below 300 kV, one-third of costs are socialized, with two-thirds of costs allocated to the zone in which the facilities are located. The costs of facilities operating at or under 100 kV are allocated fully to the zone in which the facilities are located (ER10-1069).

FERC Revises Gas Reporting Rules
FERC has further clarified (through in Order No. 704-C) Form No. 552, under which natural gas market participants must annually report information regarding physical natural gas transactions that use an index or that contribute to or may contribute to the formation of a gas index (RM07-10-002). Order No. 704-C revises Form No. 552 so as to (1) exempt from reporting any unexercised options to take gas under a take-or-release contract; (2) clarify the definition of exempt unprocessed natural gas transactions as those involving gas that is both not yet processed (to separate and recover natural gas liquids), and still upstream of a processing facility; (3) exempt from reporting cash-out and imbalance transactions, since they were burdensome to report and provided little market information; and (4) strike the form's references to the blanket sales certificates issued under § 284.402 or § 284.284, since they were burdensome to report and provided little market information, so as to also exempt small entities who were obligated to report solely by virtue of possessing a blanket sales certificate.

FERC Issues Demand Response Action Plan
FERC released a final version of its National Action Plan on Demand Response, which largely recommends the formation of a coalition of stakeholders, development of various research and education programs and forums, and the creation of an online clearinghouse of demand response information. The plan does not address any substantive policy issues (e.g. dynamic pricing, demand response compensation, etc.)

Pa. Security ... from 1

security amount, since the law provides LDCs with the discretion to set the security amount and states that the criteria used, "shall include, but not be limited to, the financial impact on the natural gas distribution company ... of a default or subsequent bankruptcy of a natural gas supplier." Because the LDC may take into account criteria other than the cost of replacement gas when establishing a security amount for a supplier, the Commission found that it would be inappropriate to adopt one standard formula to calculate the security amount for use by all LDCs.

However, the PUC noted that some LDCs may use their own formulas to calculate the level of security for suppliers operating on their systems. These formulas were established in the LDCs' restructuring proceedings for the retail supply market, and involve the peak day demand estimate for capacity, the number of days potential exposure in the billing cycle, and the commodity estimates for quantity and cost. "Again, to promote transparency of credit requirements for licensing, we will direct a NGDC that uses a formula to calculate security amounts to include the formula with other applicable rules for its use in its tariff," the PUC ordered.

The Commission struck from the current regulations the prohibition on adjusting a supplier's security amount more than once in a six-month timeframe. LDCs will be allowed to adjust a supplier's security, "as circumstances warrant."

The final rule defines a significant change in the number of customers served, volume of gas delivered, or unit price of gas (all of which may prompt a change in security) to mean a 25% change in any of the preceding metrics over a 30-day period.

The PUC also held that an LDC may consider a supplier's operational history on other LDC systems in determining the appropriate security level (such as compliance with operational flow orders or instances of failure to deliver gas).

The Commission expanded the acceptable forms of security to include the netting of LDC gas supply purchases from a supplier against that supplier's security requirements.

The regulations maintain a dispute resolution process in which a supplier can petition the PUC to adjust the amount of security as determined by the LDC, and the Commission declined to require suppliers to use an informal mediation process before a supplier may file a formal complaint with the Commission. The order holds that, "the NGDC's determinations in regard to the security amount or the forms of security it will accept is subject to Commission review and must be reasonable in regard to the individual supplier and consistent in regard to all suppliers to guard against discriminatory or anti-competitive conduct."

The PUC ordered LDCs to file annual reports on implementation of the security provisions.

Central Hudson ... from 1

A new MFC Administration Charge will then be created, containing supply procurement-related credit and collections costs and 50% of procurement-related call center costs, both of which are currently recovered through the MFC Supply Charge.

Costs for delivery-related advertising and promotions, which are currently recovered through the MFC Supply Charge, would be moved into base rates as well.

With such changes, the new MFC Administration Charge is to include the commodity-related credit and collections component and 50% of commodity-related call center costs, plus Administrative and General (A&G) and rate base items associated with each component. These costs are to be bypassable for customers on dual billing, but must be paid by customers on bundled service or ESCO service with utility consolidated billing.

The new MFC Supply Charge is to include commodity-related procurement costs, 50% of the commodity-related call center costs, commodity-related advertising and promotion costs, and related A&G expenses and rate base items allocated to each component. These costs are to be bypassable for all ESCO customers regardless of billing option, and must be paid by bundled service customers.

The joint proposal calls for the extension of mandatory hourly pricing for full service customers to customers with demands of 300 kW or greater, from the current 500 kW cutoff. The joint proposal does not provide a timeline for when the 300 kW threshold would be implemented, but calls for Central Hudson to file an implementation plan within two months of a Commission order accepting the joint proposal.

Staff has said that the expansion of mandatory hourly pricing to customers above 300 kW should occur in early 2012.

Based on Staff's testimony during the case, Central Hudson has 108 customers that have a demand level above 300 kW, but below 500 kW. Of these 108 customers, 66 receive their commodity from an ESCO, so 42 full service customers would be switched to the hourly pricing tariff under the joint proposal, as of the date of Staff's testimony.

Under the joint proposal, the existing Energy Cost Adjustment Mechanism and Gas Supply Charge mechanism, and the allocation of Power Purchase Agreement costs/benefits, are to continue per the 2009 Rate Order.

The existing retail access migration-related lost revenue mechanism would also continue per the 2009 Rate Order, in which fifty percent of retail access migration-related lost revenue is collected through the Supply Charge component of the Merchant Function Charge, which is avoided by retail access customers, and fifty percent is collected through the transition adjustment paid by all customers.