Energy Choice Matters

October 22, 2009

Pa. Draft Would Not Allow Direct to Automatically Retain Pike County Aggregation Customers

Direct Energy would not be allowed to retain customers served under the Pike County Light & Power aggregation upon its expiration on May 31, 2011, absent receiving affirmative consent from the customer to continue service with Direct, a recommended decision from a Pennsylvania ALJ would hold.

Specifically, the ALJ recommended that, "the customers of the Aggregation Program make an affirmative choice as to whom they wish to supply their electric service pursuant to Section 2807(d) of Act 129 and prior to the expiration of the Aggregation Program."

Oddly, the recommended decision does not explicitly state that customers failing to make such an affirmative decision will be automatically returned to Pike County's default service, but given that customers would not be retained by Direct, and the legal question before the ALJ in the case, ostensibly the draft decision would place such customers back onto default service. The ALJ does note, without comment, that Section 2807(e)(3.1) of Act 129 requires that if a customer does not choose, the default service provider shall provide service pursuant to a Commission approved competitive procurement plan.

The aggregation program was originally instituted as a measure to mitigate high default service rates at Pike County caused by purchasing 100% of its requirements in the wake of Hurricane Katrina. Direct, which first proposed the program, was selected as the supplier from several providers, and was transferred customers in Pike's territory on an opt-out basis. While the program

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Calif. Draft Would Modify RPS Compliance Target to Use Current-Year Retail Sales

A California PUC proposed decision would partially grant a petition from several competitive retailers and find that, starting in 2010, the annual procurement target (APT) of renewable energy for compliance with the California renewable portfolio standard shall be based on a load serving entity's current-year retail sales, rather than its year-ago retail sales.

Accordingly, starting in 2010, the 20% annual procurement target would apply to an LSE's sales in the current year. The annual procurement target is currently based on prior-year sales.

The proposed decision bases this conclusion on a statutory argument, and not practical considerations raised by retail suppliers and other petitioners during the case. The petition was filed by Constellation NewEnergy, Direct Energy, several large customer groups, and TURN.

The draft notes that Section 399.15(b)(1) of the Public Utilities Code provides that an LSE must increase its RPS-eligible procurement, "so that 20 percent of its retail sales are procured from eligible renewable energy resources no later than December 31, 2010."

"Since the deadline is the last day of 2010, measuring compliance with it requires simply a calculation of the proportion of RPS-eligible energy to total retail sales in 2010. The formula set forth in D.06-10-050 (APT = 20% of prior year total retail sales) does not capture the necessity for RPS compliance in 2010 to be measured as a 2010-based quantity," the draft concludes in finding that

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PECO Reports Prices from Second Default Service Procurement

PECO announced that its September procurement for default service supplies for the period beginning January 1, 2011, resulted in a price of 9.16¢ per kilowatt-hour for residential customers. When blended with a June procurement, the average residential price for supplies procured thus far is 9.41¢ per kilowatt-hour, which is about 4% higher than the current capped rate.

The September solicitation also included PECO's first procurement of small and mid-sized commercial supplies, at a retail price of 9.79¢ per kilowatt-hour, which PECO said is on par with the current capped rates.

PECO reported that the September 2009 residential price of 9.16¢ per kilowatt-hour resulted from a wholesale energy price of 8¢ per kilowatt-hour. The small commercial price of 9.79¢ per kilowatt-hour resulted from a wholesale energy price of 8.59¢ per kilowatt-hour.

Thirteen suppliers qualified to submit bids in both the residential and commercial September procurements.

Md. PSC Fines Goldstar Energy $2,250 for Brokering Prior to Licensing

The Maryland PSC imposed a civil penalty in the amount of $2,250 on Goldstar Energy Group for brokering electric customers in the state prior to licensing. The PSC also granted Goldstar an electric broker license to serve non-residential customers at the four investor-owned utilities, Choptank Electric Cooperative, and Southern Maryland Electric Cooperative (Only in Matters, 6/18/08).

The case differs from other recent broker applications involving brokers who were active in Maryland without a license, because those brokers said that they were unaware of the licensing requirement. In those cases, the brokers were generally granted licenses and fined either $100 or their unpaid Commission assessment for Maryland revenues.

However, in a letter order issuing Goldstar's electric license, the Commission noted that Staff deemed Goldstar's unlicensed activity to be, "knowing and intentional." According to the letter order, after Goldstar applied for its license in June 2008, it engaged in brokering activity prior to receiving the license. Staff said that Goldstar's brokering began in October 2008.

Bryan Cicalese, Goldstar's Northeast Regional Sales Manager, informed the Commission that he had failed to confirm that the license application had been granted, and had informed a consultant that Goldstar had filed its application. The consultant subsequently brokered load.

After Cicalese appeared at the Commission's October 7 meeting, the Commission said that it, "finds that Mr. Cicalese and the consultant (who actually solicited the business in Maryland) were fully aware that an electricity supply broker license was required to be issued to the Company prior to engaging in electric supply broker services in Maryland ... Mr. Cicalese and the consultant should have been more diligent in assuring that a license had in fact been issued to the Company as each were well aware that a license was required to conduct electricity supply broker services in Maryland."

Cicalese, along with Richard Jingoli, Director at Goldstar, and Renee Musicus, another Goldstar employee, formerly worked at NCG Energy Solutions. Cicalese and Musicus both appeared before the Commission in May 2008, reporting various allegations of improper behavior by NCG, which eventually led to a cease and desist order from the PSC against NCG, and a civil penalty of $150,000.

The Commission also granted Goldstar a natural gas broker license to serve non-residential customers at Baltimore Gas and Electric, Washington Gas Light, Columbia Gas of Maryland, Chesapeake Utilities, and Elkton Gas. Goldstar did not broker natural gas service prior to licensing.

MISO Files Refinements to Module E Tariff

The Midwest ISO filed at FERC a host of refinements and clarifications to its tariffs governing the Module E resource adequacy construct, including provisions to facilitate the use of the previously established standard, defined capacity product (Planning Resource Credit).

Among other things, the tariff revisions clarify that Planning Resource Credits (PRCs) that are qualified from a Planning Resource may exist independently of the Planning Resource from which the PRCs originated. Accordingly, the revised tariffs replace an LSE's obligation to designate Planning Resources with the requirement to designate PRCs to meet resource adequacy obligations.

The tariffs would provide for three types of PRCs, to recognize the varying ability of the underlying Planning Resources to be deliverable to Load within the Midwest ISO Region: (1) Aggregate PRCs (APRCs), which are universally deliverable throughout the Midwest ISO Region; (2) Local PRCs (LPRCs), which are only deliverable to a local area; and (3) External PRCs (EPRCs), which are PRCs that are qualified from External Resources.

With the implementation of the PRC concept, MISO said that the tariff should be clarified such that only APRCs can be used in the Voluntary Capacity Auction.

Stakeholder discussions also revealed the benefits of adding a new Section 69.7.d concerning how the Voluntary Capacity Auction would be cleared if the APRC Bids and APRC Offers submitted in the auction do not meet at a single point (i.e., there is a range of cleared prices). MISO said that the "most reasonable and equitable approach" would be to calculate the Auction Clearing Price as the mid-point between the Demand Bid and Supply Offer prices within such range.

Additionally, in response to stakeholder feedback, MISO filed changes to grant LSEs and capacity sellers more time prior to the Voluntary Capacity Auction to conduct bilateral transactions. The modifications would (1) lengthen the time from seven to twelve business days before the Resource Plan Deadline for LSEs interested in purchasing APRCs in the Voluntary Capacity Auction to submit APRC Bids; (2) lengthen the time from seven to twelve business days before the Resource Plan Deadline for Market Participants interested in selling APRCs to submit APRC Offers; and (3) lengthen the time from five to ten business days before the Resource Plan Deadline for the Midwest ISO to conduct the Voluntary Capacity Auction.

MISO also proposed to modify the standard governing an LSE's monthly forecast. Under the proposed tariff, an LSE's monthly forecasted demand for each Load CPNode must reflect a 50 percent probability that the demand will not exceed the forecasted demand.

MISO's revisions would also clarify that an LSE's deficiencies will be separately calculated on a Load CPNode basis. "This modification is required because forecasted Demand is provided to the Midwest ISO by LSEs on a CPNode basis and deliverability requirements mandate that deficiencies also be calculated on a CPNode basis," MISO said.

In addition, MISO proposed to modify the tariff to clarify that if there are multiple Planning Reserve Margins for different Planning Reserve Zones, then an LSE's deficiencies will be separately calculated on a CPNode basis for each Planning Reserve Zone where the LSE serves load. In the event that an LSE is determined to be capacity deficient, such LSE will be allowed to correct any errors in the Module E Capacity Tracking Tool (MECT), if that the LSE has sufficient PRCs overall, but has failed to designate enough PRCs to meet its Planning Reserve Margin Requirement at each Load CPNode.

MISO would also clarify the must-offer obligation, which requires LSEs to offer capacity resources into the Midwest ISO's Day-Ahead Energy Market and the Reliability Assessment Commitment process. Furthermore, the proposed must-offer language would specify that External Resources must be available to schedule Energy into the Midwest ISO Region if necessary in the Day-Ahead Energy Market. Finally, the Midwest ISO proposed to modify the must-offer provisions to clarify that must-offer requirements will reflect resource operational limits, including those related to Use Limited Resources and Intermittent Generation.

OCC Says Duke PTC-AAC Changes Would Increase Bypassable Costs Under SSO

The Ohio Consumers' Counsel objected to Duke Energy Ohio's petition to change how two components of bypassable Rider PTC-AAC (annually adjusted component) are adjusted, arguing that the changes will allow Duke to recover more revenue from Standard Service Offer customers (Only in Matters, 9/2/09).

As only reported in *Matters*, Duke applied to remove environmental reagent costs from Rider PTC-AAC, and to move such costs into bypassable Rider PTC-FPP (fuel and purchased power), which is reconciled quarterly rather than annually.

While both riders are bypassable, OCC noted that any retail electricity sales and associated revenues lost due to customer switching will be added back in calculating Rider PTC-AAC, and that Duke is required to make up the difference. On the other hand, Rider FPP is fully recovered from Standard Service Offer customers even if there is customer shopping. "OCC is concerned that if Duke's proposed change is approved, the non-switching customers will bear a larger share of the environmental reagent expenses than they will under the original Rider PTC-AAC."

"[I]t appears that the Company is shifting costs away from itself to the standard service offer customers by moving the environmental reagents from Rider AAC to Rider FPP," OCC added.

Duke also proposed a change in how Rider PTC-AAC is calculated, proposing to end the use of "little g" and instead use Rider SRA-CD (capacity dedication). "Little g" represented the generation-related costs that were included in rate base at the time of Duke's last generation rate case in 1992, and was changed in Duke's electric security plan and renamed PTC-BG, which changes each year.

Duke proposed that, rather than computing "little g" directly, it would divide the Rider SRA-CD revenues by 6% to derive a value of the "little g" revenue.

OCC said that in asserting the 6% relationship between Rider SRA-CD and "little g," Duke has already established the value of "little g", and said that such value can be used directly in calculating the PTC-AAC rates. OCC further said that it is unlikely that the 6% relationship between Rider SRA-CD and "little g" will remain unchanged in the future, since "little g" will increase during the electric security plan period while SRA-CD remains unchanged in the same period. If the Duke proposal is adopted, the SRA-CD imputed "little g" will be lower than the actual "little g" for the remainder of the electric security plan period, and Duke's customers will have to pay a higher PTC-AAC rate, OCC claimed.

Additionally, OCC noted that in its petition, Duke said that Rider SRA-CD is nonbypassable. While the rider is considered unavoidable, the rider is essentially bypassable for certain non-residential shopping customers who agree that any return to Duke for supply service will be priced at market rates. Such customers receive a shopping credit equal to Rider SRA-CD.

"Accordingly, relying upon Rider SRA-CD rather than the 'little g' to calculate the AAC will have a broader impact than Duke set forth when it indicated that Rider SRA-CD is nonbypassable," OCC said.

PWRPA Files Complaint Against PG&E Over Denial of Service Under Wholesale Distribution Tariff

The Power and Water Resources Pooling Authority (PWRPA), a California joint powers authority comprised of 15 public water purveyors, filed a complaint at FERC regarding Pacific Gas & Electric's refusal to provide service to PWRPA for delivery of power to one of PWRPA's retail customers, the Glenn-Colusa Irrigation District, under PG&E's Wholesale Distribution Tariff.

"The refusal is apparently due to PG&E's efforts to avoid any action that may enable or encourage an irrigation district or other potential electric supplier to serve load that PG&E would prefer to serve," PWRPA alleged.

The main dispute centers on whether PWRPA is an "electric utility" and eligible for service under the Wholesale Distribution Tariff for two new delivery points needed in order for PWRPA to serve additional load in Glenn-Colusa. PWRPA currently provides retail service to 11 delivery points within the Glenn-Colusa district.

According to PWRPA, PG&E denied the

request because PG&E does not believe PWRPA is an electric utility.

PWRPA said such an assertion is based on "two flawed interpretations of California state law."

First, PWRPA argued that it meets the definition of "electric utility" under the Federal Power Act, which it said is the standard that governs a FERC tariff, regardless of its status as an electric utility under California law.

While PWRPA does not believe California law governs the tariff, it contended that it is an electric utility under California law recognized by the California PUC and California Energy Commission.

PWRPA noted that under the California Public Utilities Code, the term "Local publicly owned electric utility" is defined to include, "an irrigation district furnishing electric services formed pursuant to the Irrigation District Law set forth in Division 11 (commencing with Section 20500) of the Water Code, or a joint powers authority that includes one or more of these agencies and that owns generation or transmission facilities, or furnishes electric services over its own or its member's electric distribution system."

PG&E has argued that the participation of PWRPA's non-member stakeholders on PWRPA's Board of Directors, when such stakeholders are not authorized under California law to sell electricity at retail, necessarily means that PWRPA is not authorized to act as an electric utility under California law. Because only irrigation districts are allowed to sell electricity, and water district representatives are included within PWRPA's Board of Directors, the "common" powers among PWRPA's irrigation district members no longer include the sale of electric energy, PG&E has said.

PWRPA countered that California's Joint Powers Act allows "two or more public agencies by agreement" to "jointly exercise any power common to the contracting parties." PWRPA said that because the contracting parties to the PWRPA Joint Powers Agreement are all public agencies of the State of California established pursuant to Division 11 of the Water Code Section 20500 et seq., dealing with Irrigation Districts, PWRPA retains its authority to sell retail electricity.

PG&E also said that PWRPA must first receive approval from the applicable Local Agency Formation Commission under the California Government Code before providing service, but PWRPA argued such an issue is a state matter, and cannot be used to deny service under a FERC tariff.

Briefly:

Paragon Advisors Seeks Pa. Electric License
Paragon Advisors applied for a Pennsylvania electric broker license to serve commercial customers over 25 kW, industrial customers, and governmental customers. Paragon said that it will initially focus on PPL. Paragon is active in brokering loads in Connecticut, Massachusetts, and Rhode Island.

AGR Group Seeks. Md. Electric License
AGR Group, Inc., applied for a Maryland electric broker license to serve all classes of customers at the four investor-owned utilities, Choptank Electric Cooperative, and Southern Maryland Electric Cooperative. As only reported in *Matters*, AGR has a pending Pennsylvania broker application (Only in Matters, 10/20/09).

Aspen Energy Receives Ohio Licenses
The Public Utilities Commission of Ohio granted Aspen Energy Corporation a natural gas broker/aggregator license for all customer classes in all LDC territories, and an electric broker/aggregator license to serve all customer classes in all service territories (Only in Matters, 9/23/09).

Taylor Consulting and Contracting Receives Conn. License
The Connecticut DPUC granted Taylor Consulting and Contracting an electric aggregator certificate to serve commercial, industrial, municipal and governmental customers (Only in Matters, 7/30/09).

PUCT Approves Texas Energy Transfer Power REP Certificate Amendment
The PUCT approved the application of Texas Energy Transfer Power for an amendment to the REP certificate of TexRep4 LLC to reflect its acquisition of the certificate, and to change the certificate from an Option 1 certificate to an Option 2 certificate. As only reported in *Matters*,

Texas Energy Transfer Power's initial customer list required of Option 2 REPs only lists various affiliates of its parent, Energy Transfer Partners (Only in Matters, 10/12/09).

PUCT Approves Tara, Amigo Certificate Amendments

The PUCT approved amendments to the REP certificates of Tara Energy and Vega Resources (Amigo Energy) to reflect the acquisition of Tara by Vega's parent, Fulcrum Power Services, and various corporate reorganizations (Only in Matters, 9/4/09). Amigo's certificate was changed to reflect the new legal name of Fulcrum Retail Energy LLC rather than Vega Resources; Amigo will continue to be the name used for marketing and to provide service.

Power Tree Receives Texas Aggregation Certificate

The PUCT granted Power Tree Inc. an aggregation certificate to pool residential, commercial and industrial customers.

Pepco to End D.C. Dynamic Pricing Pilot With October Billing Period

Pepco notified the District of Columbia PSC of its intent to terminate the PowerCentsDC dynamic pricing pilot for residential customers with the October billing cycle, rather than the February 2010 billing cycle. Pepco said that its unnamed third-party billing vendor informed Pepco that the vendor is unable to provide billing services after the month of October. As the pilot has already accrued two years worth of summer data, the D. C. Smart Meter Pilot Program board decided to end the program rather than attempt to continue billing under dynamic pricing without a third-party vendor, due to logistical concerns. Customers will be returned to the normal SOS rates.

DPUC Approves CL&P Last Resort Service Procurement

The Connecticut DPUC approved Connecticut Light and Power's procurement of 100% of Last Resort Service supplies for the three-month period beginning January 1, 2010. Retail rates must be posted by November 17, 2009.

PUCT Issues Meter Tampering Workshop Notice

The PUCT issued a public notice regarding the November 6 meter tampering workshop first announced at the October 8 open meeting (Only in Matters, 10/9/09). The Commission also announced that the second customer disconnect protection workshop on Nov. 20 will begin at 1:30 p.m. local time, instead of 9:30 a.m.

Pike County ... *from 1*

was extended through May 2011 earlier this year, the PUC set for briefing the question of what should happen to customers at the end of the renewed aggregation term.

Direct and Pike County argued that Direct should retain customers who do not otherwise make an affirmative choice, as Direct said that it is serving the customers as it does any other competitive customers, who cannot forcibly be removed. The Office of Consumer Advocate contended that customers should be returned to default service absent affirmative consent, since Direct assumed the customers on an opt-out basis, and Pennsylvania law requires an affirmative choice to serve customers competitively (Only in Matters, 6/24/09).

The ALJ agreed with OCA. Section 2807(d)(1) of Act 129 requires the PUC to establish regulations that, "an electric distribution company does not change a customer's electricity supplier without direct oral confirmation from the customer of record or written evidence of the customer's consent," the ALJ said. "This language makes it apparent that the power of choice lies specifically with the customer and further, that the choice is to be made through direct oral confirmation from the customer of record, or through written evidence of same," the ALJ concluded.

Direct had argued that since its service to aggregation customers is "no different" from other competitive options, it has the right to automatically renew customers absent affirmative consent, as it noted in its initial pleadings to create the pool in 2006. The PUC's original order, Direct observed, held that contract extensions for aggregation customers would be permissible so long as they conformed to Commission regulations. At no time has the

PUC held that an affirmative consent is needed to continue serving customers at the end of a product's term, Direct added.

However, the ALJ found that because the aggregation rates and terms were under the oversight of the PUC, Direct's service is not analogous to serving other competitive customers, and that Direct is not entitled to automatically renew the aggregation customers. As the PUC will no longer oversee specific rates and terms after the aggregation program ends, the ALJ concluded that customers must affirmatively choose to remain with Direct.

"Therefore, at the expiration of the Aggregation Program, it is necessary for the customers to affirmatively choose. I believe that this is not only legally accurate, but also highly appropriate in this territory. As has been painfully detailed in the history of this case and the history of electric competition (or lack thereof) in this territory the customers have perceived that they did not have a voice. Act 129 firmly ensures that customers have and affirmatively use their voice to choose their electric provider," the ALJ concluded.

Calif. RPS ... *from 1*

the formula should be altered to use current-year sales.

Retail suppliers had noted that use of the prior-year sales total in calculating the target would require suppliers which have lost load versus the year-ago period to over-procure renewable energy based on their current customer base. Moreover, such renewable costs would be imposed on a smaller number of current customers, and not necessarily those customers who prompted the larger RPS obligation. Using the current-year sales data to set the RPS target would allow suppliers to more fairly allocate compliance costs among customers, suppliers said.

However, the proposed decision found such an argument to be largely based on the assumption that a supplier's ability to sign new customers will continue to be limited by the current suspension of direct access. Under the suspension, a supplier's load is more likely to decrease rather than increase, though the draft observes that any individual supplier may experience an increase in sales because it acquires a customer from another competitive supplier.

The draft said that the reopening of direct access could change the zero-sum situation for suppliers postulated by the petition, and noted that SB 695 permits a phased resumption of direct access for non-residential customers subject to a cap.

"Thus, the situation ... may be about to change," the draft says.