Energy Choice Matters

August 18, 2010

Direct Energy Proposes Retail Auction to Mitigate FirstEnergy-Allegheny Merger Concerns

Direct Energy has proposed that, as a condition of the merger between FirstEnergy (FE) and Allegheny Power, retail customer auctions should be used in Pennsylvania to serve non-shopping customers at Met-Ed, Penelec, Penn Power, and West Penn Power, as Direct contended that the merged company, with nearly 40% of the state's load, would produce an anticompetitive climate if the distribution utilities remained as default service providers (A-2010-2176520).

"[T]he continuation of the FE utility operating companies in the role of default service provider would constitute anticompetitive and discriminatory conduct that would deprive customers in the service territories of those companies of the benefits of a workable competitive market," said Direct Energy Business's Director of Products and Complex Transactions Frank Lacey, a noted expert on regulatory affairs and market development. Direct also presented expert testimony from former Pennsylvania PUC and FERC Commissioner Nora Mead Brownell, on policy issues, and Dr. Mathew Morey, a senior consultant at Christensen Associates, on economic and market power issues.

Pennsylvania's Choice Act requires that the Commission must consider whether mergers will result in anticompetitive conditions which would prevent customers from obtaining the benefits of a workably competitive retail electric market.

Direct recommended that, to begin, the Commission should select an alternative default service provider for the four service areas as a condition of the merger. However, this newly designated default service provider, which Direct said should not be an affiliate of FirstEnergy or Allegheny,

Continued P. 5

Illinois Power Agency Submits Procurement Plan

The Illinois Power Agency has submitted its draft procurement plan for the period June 2011 through May 2016 which largely relies on the current three-year laddering process, but also includes several new features such as the procurement of demand response at Commonwealth Edison, and additional "optional" procurements to fill unsubscribed load.

The IPA's plan maintains the use of an annual spring procurement relying on RFPs. The resources sought through the RFP events will be:

- At Ameren: Energy, Capacity, and Renewable Energy Resources
- At ComEd: Energy, Demand Response in lieu of Capacity, and Renewable Energy Resources

Aside from the annual spring procurement, IPA proposes to implement optional procurements of up to an additional 10% of projected portfolio requirements in any month that is below the 100% subscription level. The optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the target months are below the average weighted price of fixed price contracts already secured by the utilities for those months. The optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the spring 2011 solicitation, and allowed only with the authorization of the Illinois

Continued P. 8

Central Hudson Proposes Oct. 2012 Start for Expansion of Hourly Pricing to 300 kW

Central Hudson Gas & Electric has proposed to begin mandatory hourly pricing for default service customers between 300 kW and 500 kW on October 1, 2012, in an implementation plan filed with the New York PSC (09-E-0588).

As only reported in *Matters*, the Commission ordered the expansion of hourly pricing from the 500 kW cutoff to customers with demands greater than 300 kW in Central Hudson's most recent rate case; however, the Commission did not establish a timeline for implementation in its order (Only in Matters, 6/18/10).

Central Hudson plans to begin meter installation for these customers in March 2011, and expects installation will take seven months. The proposed October 2012 start date reflects the desire that customers have 12 months of interval usage prior to the start of hourly pricing.

Currently, Central Hudson has 164 customers on S.C. No. 2 with demands between 300 kW and 500 kW. As of June 30, 2010, 90 of these customers are on competitive supply.

Seminars to be held with affected customers prior to the switch to hourly pricing will include a discussion of retail access, and the opportunity for customers to speak with ESCO representatives.

Md. PSC Staff Recommend Additional Charges Be Included in BGE SOS Admin. Charge

Similar to its recommendations for the Pepco utilities (Only in Matters, 8/10/10), Maryland PSC Staff have recommended including additional costs in the SOS Administrative Charge at Baltimore Gas & Electric, to account for costs incurred in supplying customers with power but which are currently collected in distribution rates (Case 9221).

Specifically, Staff testified that the following costs should be included in the bypassable SOS Administrative Charge as a new "Allocated Cost" component:

- Customer accounts expenses
- Billing expenses
- Credit and collection expenses
- Customer service expenses
- Customer information expenses

Staff said that such expenses are classified as Customer Accounts Expense Operations and Customer Service and Information Expense Operations in FERC's Uniform System of Accounts. Staff said that such costs should be allocated to the Administrative Charge based on the SOS portion of the utilities' electric revenues.

Similar to the current mechanism, such costs would be collected only from SOS customers, but would then be credited, through the Administrative Credit, to all distribution customers. In this way, SOS customers are properly allocated such costs in the absence of the full unbundling of distribution rates, Staff said.

Staff's new SOS Administrative Charge would include: (1) a Return Component, (2) an Incremental Cost Component, (3) a Cash Working Capital (CWC) Component, and (4) an Allocated Cost Component.

Staff proposed retaining the existing return levels as set in Case 8908.

Furthermore, Staff proposed retaining the current amount of the Incremental Cost Component for Type I and Type II customers, except that no portion of Cash Working Capital Costs will be considered to be collected as part of the Incremental Cost Component.

Staff's proposal would set the Incremental Cost Component at 3.5 mills/kWh for Type I customers and 4.0 mills/kWh for Type II customers. For hourly customers, Staff would set the Incremental Cost Component at 0.75 mills/kWh.

For residential customers, Staff proposed combining the 0.5 mills/kWh designated for incremental costs with the 2 mills/kWh designated for uncollectibles to create a 2.5 mills/kWh Incremental Cost Component.

Staff supported setting the Cash Working Capital Component as the cost of Cash Working Capital less the amount of Cash Working Capital considered to be collected as part of the Return Component of the Administrative Charge.

Staff's Administrative Charge would be updated annually June 1 to reflect actual Cash Working Capital Costs. Additionally, the Administrative Credit paid to all distribution customers would be adjusted each June 1, to reflect revenue collected by the Incremental Cost Component less actual incremental costs, in addition to the refund of the Allocated Cost Component.

Staff proposed that the higher Cash Working Capital recovery costs take effect immediately upon a Commission order, and that its other proposed changes, such as the new Allocated Cost Component, take effect June 1, 2011.

Similar to its testimony in the Pepco case, the Office of People's Counsel argued that the administrative credit should only be credited to SOS customers. Refunding the charges to all distribution customers, "gives rise to slight cross-subsidization of switching customers by SOS customers, since customers that switch to competitive retail supply will not be charged the Administrative Adjustment, but will be credited a portion of the revenues," OPC said.

"After a decade of competition in the supply of electricity to consumers, the retail market is fully developed and mature. At this point, it is neither necessary nor reasonable to charge SOS customers more than the actual cost of residential SOS - and to require that SOS customers subsidize customers served by retail suppliers in the process of crediting Administrative Adjustment revenues - in order to provide an artificial competitive edge to retail suppliers," OPC added.

OPC proposed eliminating the return component from the Administrative Charge (except as related to cash working capital), and basing BGE's incremental Cash Working Capital costs on short-term rather than long-term debt.

OPC proposed the following residential Administrative Charge:

Incremental Cost	0.13 mills/kWh
Uncollectible Cost	1.59 mills/kWh
Return (CWC)	0.58 mills/kWh
Total	2.30 mills/kWh

This compares to BGE's proposal of:

Incremental Cost	0.13 mills/kWh
Return	1.50 mills/kWh
Uncollectible Cost	1.59 mills/kWh
CWC Cost	1.28 mills/kWh
Total:	4.50 mills/kWh

Reliant Energy Offering Residential Index Product with Price Cap

Reliant Energy has introduced a residential Cap-and-Save product that provides customers with a locked-in price and automatically decreases if energy prices drop.

The plan is essentially a 12-month indexed product with a price cap on the commodity rate.

At Oncor, the initial indexed energy charge is capped at 8.8¢/kWh, which, when adding nonbypassable distribution and ERCOT charges, equates to an all-in price of 12.0¢/kWh based on 1,000 kWh usage.

At CenterPoint, the initial indexed energy charge is capped at 9.3¢/kWh, which produces an all-in price of 13.3¢/kWh based on 1,000 kWh usage.

Apart from providing the EFL, the Reliant website quotes the rates on a 2,000 kWh per month basis.

The indexed energy charge is tied, on a monthly basis, to the closing price of the next month's NYMEX Natural Gas Futures Contract on the last day of options trading for that next month's natural gas contract.

The Cap-and-Save plan features 20% renewable content.

The product includes a $150 early termination fee.

Reliant elected to publicly launch the product at an event in Dallas.

Texas Longhorns Energy Releases Pricing

Texas Longhorns Energy, the affinity partnership among the University of Texas, Branded Retail Energy Company, and Champion Energy Services, announced pricing for its previously reported renewable offers in ERCOT (Matters, 7/27/10).

For residential customers, 12 and 24-month 100% renewable plans are available.

At Oncor, the 12-month plan costs 10.6¢/kWh, and the 24-month plan costs 11.1¢/kWh.

At CenterPoint, the 12-month plan costs 11.8¢/kWh, and the 24-month plan costs

12.3¢/kWh. These charges reflect 1,000 kWh of usage per month.

Apart from providing the EFL, the Texas Longhorns Energy website quotes rates on a 2,000 kWh per month basis.

The 12-month plan includes a $150 early termination fee, and the 24-month plan includes a $250 early termination fee.

Texas Longhorns Energy also confirmed, as postulated by *Matters*, that it will sell RECs to customers in non-competitive areas of Texas.

Briefly:

CL&P Reports Last Resort Service Rates

Connecticut Light & Power posted Last Resort Service rates for the three-month period beginning October 1, 2010.

(¢/kWh)	GSC	FMCC-Generation	Total Generation
October	6.337	0.300	6.637
November	6.577	0.300	6.877
December	7.358	0.300	7.658

Applicable to customers at or above 500 kW on Rates 21, 39, 41, 55, 56, 57, 58
On-Peak and Off-Peak rates identical

Border Energy Receives Ohio Electric License

The Public Utilities Commission of Ohio granted Border Energy, Inc. an electric supplier license to serve all customer classes, including residential customers, in all service areas (Only in Matters, 7/12/10).

BidURenergy Receives Ohio Broker License

The Public Utilities Commission of Ohio granted BidURenergy, Inc. an electric broker/aggregator license to serve all customer classes in all service areas (Only in Matters, 7/19/10).

Xencom Green Energy Seeks Pa. Broker License

Xencom Green Energy, LLC has applied for a Pennsylvania electric broker license to serve commercial customers over 25 kW in all service areas.

PUCT Opens Informational Project on Entergy System Agreement

The PUCT has opened Project 38572 as an informational project relating to Entergy Texas, the Entergy System, and the Entergy System Agreement.

Mass. DPU Denies Nstar Contracts Procured Before Change Allowing Out-of-State Projects

The Massachusetts DPU dismissed without prejudice Nstar's application for separate long-term contracts to purchase wind power and associated renewable energy certificates from New England Wind, LLC; Pioneer Valley Wind, LLC; and American Pro Wind, LLC because the competitive bid was limited to in-state projects, a requirement that the DPU lifted in response to legal challenges from TransCanada Power Marketing (Dockets 10-71. et. al.).

DPUC Draft Would Approve CL&P Metering Rates

The Connecticut DPUC would approve Connecticut Light & Power's revised Electric Restructuring Rates and Charges under a draft decision in Docket 98-01-02RE04. The proposed rates, relating to various metering options (such as Pulse Output) and off-cycle reads, were previously detailed in our March 21, 2010 story.

NYISO Creates Consumer Interest Liaison

The New York ISO has created the new position of Consumer Interest Liaison, which is to work closely with the New York State Consumer Protection Board, the New York State PSC, other government agencies, end-use consumers, and ratepayer advocates, "to drive the increased effectiveness of end-use consumer representation in the NYISO governance processes." One of the key responsibilities will be the analysis of market developments and preparation of consumer-focused reports to state officials, including the governor, the attorney general, the state legislature, and the PSC.

FirstEnergy Merger ... *from 1*

should immediately institute a proceeding to auction off the right to serve non-shopping retail customers with peak demands under 300 kW. The one-time auction would grant suppliers the right to serve the acquired customers until such time as the customer makes an affirmative choice to leave their winning supplier.

Non-shopping customers that are 300 kW or larger would be served on hourly prices from the alternative default service supplier.

For residential and small commercial customers, non-shopping customers could opt-out of the auction process and remain on a backstop product with the alternative default service provider. The backstop product would be similar to the default service provided by Pike County Light & Power -- a quarterly modified generation rate established to reflect hourly spot purchases used to serve customers. This backstop service would be available in cases where a retail supplier exits the market as well.

Customers who have already migrated to competitive supply would not be included in the auction.

Under Direct's proposal, a consultant hired by the PUC would establish a retail generation rate for each customer class included in the auction to cover the initial 12 months of service (with the price fixed in six months increments). All winning retail suppliers would have to serve acquired customers at the prescribed rate.

Lacey suggested that the price should consist of a NYMEX six-month strip price (from the day before the auction) plus a consultant-determined market adder to transform the wholesale prices to retail prices. This price would apply for six months. After six months, the price would be adjusted based on the same NYMEX index, and would be guaranteed for another six months. After a total of 12 months, pricing would be at the discretion of the competitive supplier.

Suppliers would bid for the right to serve blocks of customers, which Lacey said would vary in sizes between 20,000 and 100,000 customers. Lacey testified that the varying sized blocks are intended to make the auction accessible to all sizes of suppliers. Each block would be bid out individually under an ascending clock format.

The blocks would separate residential and small commercial customers, and would be homogeneous and random, with the following exception. Customers qualifying for certain utility low-income assistance programs would be grouped into separate blocks, but would receive the same retail price determined by the PUC consultant. Other customers with poor credit, but who do not qualify for assistance programs, would not be grouped into a separate block, and would be randomly mixed into the standard blocks.

Customers obtained through the auction would not be subject to any switching restrictions or face any fee for choosing to leave their supplier as determined in the auction for a different competitive supplier.

Direct suggested requiring new customers to select a retail supplier at service initiation, rather than placing such customers on the backstop default service. Customers not making a choice could be randomly assigned to a pool of suppliers.

Direct noted that recent transactions involving the purchase of various companies' retail books have valued customers between $150 to $500 per account. Based on those numbers, the proposed auction could generate $300 million to $1 billion in revenue, given the 2 million customers across the four utilities. These revenues would be credited to customers participating in the auction as well as to those on competitive supply, but not to those who opt for backstop default service prior to the auction, in order to avoid the creation of perverse incentives that could alter customers' behavior prior to the auction.

All eligible customers would receive an equal share of this revenue, regardless of what the supplier bid to serve the individual customer. The revenues would only go the classes of customers included in the auction (e.g. under 300 kW), and not be credited to larger customers.

A small portion of revenue, anticipated to be less than 5%, would be used for customer education and to fund a BillCo proposed by Direct, discussed below.

Direct proposed that service under its auction program begin June 1, 2013, so as not to interfere with existing default service supply contracts.

As part of its auction process, Direct called for the creation of a new subsidiary of FirstEnergy focused exclusively on billing, collections, and other backoffice support (e.g. EDI) necessary to serve retail electric customers, apart from the electric distribution companies and their distribution responsibilities. This so-called BillCo would handle what were formerly utility consolidated bills, and, in the case of dual billing, would also bill for distribution service alone on behalf of the utility.

BillCo-issued bills for combined supply and distribution service would be branded with the logo of the customer's competitive supplier, including in cases where the customer was obtained through the auction.

Brownell testified that the BillCo would be able to bill for "value added" services which currently are not accommodated through utility consolidated billing.

Direct suggested that the BillCo could be located at or near Allegheny Energy's current Greensburg location, and could serve to retain those jobs in Pennsylvania which otherwise might migrate to an out-of-state FirstEnergy customer care center absent the creation of BillCo.

Speaking with *Matters* after the testimony was filed yesterday, Chris Kallaher, Director of Government & Regulatory Affairs for Direct Energy, said that Direct envisions that much of the granular details of the auction and BillCo would be worked out in a collaborative process.

Pennsylvania's regulations explicitly allow for the designation of an alternative default service supplier, and several Commissioners have recently encouraged stakeholders to propose such alternatives (Matters, 5/7/10 and 3/31/10). Although not arising from the alternative default service supplier provision, Pennsylvania has had experience with customers being assigned to a competitive supplier without affirmative action from the customer, in the PECO Market Share Threshold program, a type of retail load auction, and the Pike County aggregation program (won by Direct).

Competitive Concerns

"FE's pattern of conduct in its Ohio service territories raises serious concerns about its ability to exert market dominance in its home service territories," Lacey testified, noting that FirstEnergy Solutions has reported that it serves, through POLR, direct or aggregation sales, 78% of generation sales in its affiliated Ohio territories (Only in Matters, 8/4/10).

"The ability of the utility's unregulated affiliate to control more than three-fourths of the retail market on a sustained basis should raise serious concerns on the part of the Commission regarding FE's long-term strategy to leverage its monopoly delivery service position for the benefit of its competitive affiliates in Pennsylvania," Lacey testified.

Lacey raised concern about "potentially anti-competitive and discriminatory interactions between the FE regulated utilities and [their] unregulated affiliate," citing FirstEnergy Solutions' willingness in Ohio to offer nine-year municipal aggregation contracts at a fixed percentage off of the default service rate, even though the discount's time horizon extends well beyond the current schedule for default service.

Morey noted that the PJM market monitor has found that several markets, including the energy, reserves and capacity markets, are not structurally competitive. "The merger will only increase the concentration of generation assets in these product markets, exacerbating structural problems," Morey testified.

Direct recommended that FirstEnergy Solutions be prohibited from using a name that is similar to either FirstEnergy, Allegheny, or any of the legacy affiliate distribution company names (e.g. Penn Power, etc.) in serving retail customers in its affiliate service areas. Direct also suggested that FirstEnergy Solutions be required to divest an amount of in-state generation, or make such generation available to the market at the same price that it is made available to its affiliates, though Direct did not offer a megawatt target for such divestitures.

RESA Testimony

The Retail Energy Supply Association raised similar concerns regarding the merger, and submitted testimony proposing several remedial measures. RESA's testimony was offered by Richard Hudson, Director of Regulatory and Legislative Affairs for ConEdison Solutions and RESA's Pennsylvania State Chair. Hudson previously served in various roles at FERC.

Citing several FirstEnergy investor presentations, which have been covered in this space, Hudson testified that, "it is clear that First Energy's business strategy is to acquire retail load in the service territories of its affiliated EDCs and to use this retail load as a hedge and revenue stream for the output of the First Energy generating assets."

"First Energy clearly intends to become the dominant retail supplier in its affiliated EDC service territories," Hudson continued. "First Energy Solutions intends to aggressively pursue this strategy though long term municipal and community aggregation programs," Hudson added. Hudson noted that FirstEnergy Solutions provides annual payments of $3 to $4 million to Ohio municipalities and receives $900 million to $1 billion in annual revenue from these municipal aggregation programs.

"First Energy in uniquely able to pursue this strategy because of the inherent competitive advantages derived from its affiliate relationships. First Energy Solutions has a competitive advantage because it owns generation located geographically close to load in affiliated EDC service territories. Additionally, First Energy's investment in these assets has been paid for by all customers through stranded cost recovery," Hudson testified.

"First Energy Solutions' business strategy is essentially to become an unregulated monopoly provider of generation service to its affiliated EDC markets. I do not believe that this strategy is consistent with the goal of the Commonwealth to foster a vibrant retail market, or in the best interest of Pennsylvania rate payers," Hudson said.

Hudson testified that, "improper cost allocation may already be occurring and could easily be exacerbated by the merger." Hudson cited discovery responses from FirstEnergy stating that FirstEnergy is not allocating any costs to FirstEnergy Solutions for the shared "Government Relations" function. "This is despite the fact that First Energy Solutions benefits from the government relations activities of the combined companies. For example, First Energy is aggressively pushing a municipal aggregation bill in Pennsylvania and is, presumably, relying on the corporate government relations functions in supporting this effort," Hudson said.

Furthermore, "First Energy is not allocating any costs to First Energy Solutions for the FERC Policy and Compliance function, although FERC has jurisdiction of First Energy Solutions' market based rate authority and First Energy Solutions is subject to many other FERC compliance matters," Hudson added.

Hudson offered a number of remedial measures to answer these anticompetitive concerns raised by the merger, such as:

- Requiring a Purchase of Receivables program at West Penn Power, and expanding the Met-Ed/Penelec program to include large commercial customers
- Instituting a supplier referral program under which customers would be informed of supplier offers when calling the utility, through bill inserts, and when initiating new service
- Lowering the hourly default service pricing cutoff to 100 kW
- Serving 25-100 kW default service customers on quarterly rates, comprised of 25% spot power and 75% three-month fixed price contracts
- Serving residential and <25 kW default service customers on a mix of 25% spot purchases, 25% fixed three-month contracts, and 50% fixed contracts not to exceed one year
- Implementing a default service load cap of one-third
- Prohibiting joint marketing activities between the utilities and affiliates
- Requiring a full unbundling of default service functions and associated costs
- Shortening the timeline for implementing new rate codes (currently 90 days at the FirstEnergy EDCs)
- Removing the mention of the rescission period from the enrollment confirmation letter, as rescission is linked to the contract signing not enrollment
- Instituting a market monitor for the merged service areas, and
- Several other operational and EDI enhancements recently raised by suppliers in other dockets

Illinois ... from 1

Commerce Commission.

Energy supply at Ameren and ComEd will be sought on a laddered three-year forward basis. The IPA proposes to allow Energy Efficiency from existing Energy Efficiency Portfolio Standards programs administered by the utilities to be treated as an energy supply resource. Prices for the products would be negotiated after the closing of the spring 2011 solicitations for traditional physical and financial swap products.

As in prior plans, the laddering would be:

- 35% of projected energy needs procured two years in advance of the year of delivery;
- 35% of projected energy needs procured one year in advance of delivery, and
- 30% of projected energy needs procured in the year in which power is to be delivered.

Consistent with statute, the IPA will seek Demand Response as an alternative to Capacity Resources for both utilities. For Ameren, Demand Response sourced Capacity Resources that are qualified by the Midwest ISO to issue Planning Resource Credits, and which meet the requirements of the statute, will be sought for the Ameren load on a laddered three-year forward basis. Such assets will be bid into the Ameren Capacity procurement event where selection will be based on a price-only basis.

At ComEd, Demand Response that is qualified by PJM as a capacity resource and which meets the requirements of the statute, but which has not bid into the PJM Reliability Pricing Model (RPM) system, will be will be solicited. In the absence of qualified bids, the IPA proposes that ComEd meet the Capacity Resources requirements of the IPA load via the RPM system.

In the past, the Commission and the IPA have accepted that the RPM process satisfied the requirements of the legislation with regard to securing demand response in lieu of capacity, largely because the RPM process was considered to be market-wide and capable of capturing all cost-effective demand response assets.

"However, the IPA believes that the cancellation of the Second Incremental Auction indicates that the RPM processes may not be capturing all potential or available demand response resources," the IPA said in proposing the demand response procurement.

Renewable Energy Resources will be procured as Renewable Energy Credits for a single compliance year (June 2011 through May 2012). The IPA proposes to continue the consolidation of REC procurement processes and procedures which started in 2010, and seeks to unify standard terms and conditions between Ameren and ComEd with regard to REC contracts.