Energy Choice Matters

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# OCA, Distribution Utilities Oppose POR Mandate at PPL

Pennsylvania statute prohibits the PUC from ordering PPL to institute a Purchase of Receivables program as envisioned in a Tentative Commission Order, the Office of Consumer Advocate and Energy Association of Pennsylvania said in comments.

The Commission's Tentative Order would require PPL to develop a non-recourse POR program with little or no discount that would be in place upon the expiration of rate caps on January 1, 2010.

OCA and the Energy Association of Pennsylvania said that such a mandate is prohibited by 66 Pa. C.S. §2807(c)(3), which states, "The electric distribution company shall not be required to forward payment to entities providing services to customers, and on whose behalf the electric distribution company is billing those customers, before the electric distribution company has received payment for those services from customers." While utilities may voluntarily offer POR programs, the Commission cannot order such a program, OCA said.

The Retail Energy Supply Association countered that the Commission has broad authority to implement POR to achieve its legislative mandate of providing customers with direct access to a competitive retail market.

The Energy Association of Pennsylvania, composed of distribution utilities, further warned that, as structured, the POR program under the Tentative Order would allow competitive suppliers to cherry-pick customers, using POR for customers with poor credit while direct billing customers with good credit. The Tentative Order would not require suppliers to place all customers onto POR in order to use the program. The Energy Association of Pennsylvania noted that other territories have sought to mitigate a potential rise in utility bad debt levels through an appropriate discount, negotiation of POR terms, or requiring migrated customers with 60 days' arrearages to return to

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# CL&P Seeks Expansion of Supplies to be Bought Bilaterally, Opposes Competitive RFP

The Connecticut DPUC should affirm that electric distribution utilities may bilaterally contract for supplies in excess of 20% of Standard Service load, and should not require any long-term contracts to be solicited via competitive RFP, Connecticut Light and Power said in response to a procedural order which proposed a process to review long-term Standard Service contracts.

As only reported by *Matters*, (Matters, 6/18/09), the Department has proposed that any long-term contract proposals would be subject to a full review process, including hearings, with disclosure of the winning supplier and bid price once the contract is awarded.

CL&P sought to expand the amount of supply which may be procured bilaterally. In an April 2008 decision, the DPUC capped supplies procured via long-term contracts at 20% of Standard Service load. However, CL&P argued that such a limitation is not contained in statute, and asked that the DPUC confirm that the Department may elect to increase the cap in any proceeding in which proposed long-term contracts are reviewed.

The Department's procedural order says that long-term contracts should be evaluated side-by-

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## ConEd Says Warm Transfer Requirement for ESCO Referral Program Unworkable

The New York PSC's modification of Consolidated Edison's ESCO Referral Program to include a "warm transfer" requirement makes the program "unrecognizable" and "unnecessarily complex and impracticable," ConEd said in a petition for reconsideration (07-E-0523).

Under the Commission's order (Matters, 6/4/09), ConEd on a pilot basis for new service customers is to use a warm transfer which will require ConEd's customer service representatives to transfer the customer directly to the ESCO's call center. By allowing the warm transfer to an ESCO call center, the ESCO would serve as an agent in the enrollment process, the Commission said.

However, ConEd cautioned that the warm transfer process, "opens the possibility that the customer will not be provided service at the terms of the ESCO referral program."

Moreover, ConEd said there is no means for the ESCO to act as the utility's agent in the enrollment process. Under the Uniform Business Practices, when the ESCO enrolls a customer in retail access, the enrollment must be submitted not less than 15 days before the customer's cycle billing date. Thus, depending on the date of the ESCO enrollment relative to the customer's cycle billing date, the customer may have to be served by Con Edison for at least one billing cycle and perhaps two billing cycles before being transferred to the ESCO, ConEd said.

ConEd also offered several practical issues related to a warm transfer requirement.

For example, if the applicant is requesting both gas and electric service to be provided by two randomly assigned ESCOs, the caller cannot be transferred to both ESCOs at the same time. Additionally, the applicant may call Con Edison to initiate service during hours when the ESCO's call center is not operational.

ConEd also said that the warm transfer requirement may have negative impacts on participating ESCOs since it would require changes to the random assignment process currently used.

Under Con Edison's current referral program, the customer service rep does not know the identity of the randomly assigned ESCO. The assignment to a particular ESCO is actually made when the customer's account record is updated overnight. The letter informing the customer of his or her enrollment in retail access and the name of the ESCO that will provide service is generated automatically. "The randomness of the assignment is preserved by this procedure, which mitigates the possibility either that a customer might reject, with or without cause, a particular assignment or that an ESCO might feel that the CSRs [customer service reps] are influencing the assignments," ConEd said.

The warm transfer procedure, on the other hand, would require ConEd customer service reps to identify to the customer during the call the name of the randomly-assigned ESCO, ConEd noted, adding that is not hard to imagine a customer saying, "How about the next one on the list?" or "What do you know about that one?"

Furthermore, in order to identify the ESCO being randomly assigned to a particular applicant, ConEd will have to make system changes, for which there would be a cost. ConEd also said the warm transfer process would increase the time ConEd representatives spend on each call, due to the time to dial the ESCO and wait to ensure the customer is connected.

## CRA Says No Reliability Need for New NYC Power, But Suggests Larger Role for LSEs

There is not a critical reliability need for new transmission or generation in New York City in the near future, CRA International said in a report released yesterday. The report was prepared for the New York City Economic Development Corporation.

CRA forecast that there is neither a compelling system-wide economic nor a reliability-based argument for development of new transmission or generation. Based solely on reliability criteria, New York City would not need new generating capacity before approximately 2019 under current forecasts. Prior shortfall projections had prompted the consideration of utility-procured long-term contracts for supply.

However, CRA noted said that ratepayers would benefit from new capacity resources added or sponsored by Load Serving Entities in New York City, by (1) offsetting their capacity purchase requirement and (2) changing the market clearing point, potentially shifting prices lower.

New generation may also be desirable for various policy reasons as well, even if its costs are above market, CRA said. "Many private developers are unwilling to bear these risks [of building in the city]; development by a regulated or governmental entity, or energy and capacity contracted for by such agencies, may be an effective way to create new capacity," CRA added.

"Decision-makers should examine expanding the ability of the City, utilities, the New York Power Authority and others to drive regional power market improvements by buying or building the resources that best meet public policy objectives, or by providing financing for strategic projects that benefit the region or the State. A key element of this would be exploring regulatory or legislative mechanisms that could facilitate such an expanded role for these entities," CRA said.

## Allegheny Adjusts Customer Dispute Process Under POR

Allegheny Power has modified its proposed tariff to implement Purchase of Receivables in Maryland in response to supplier feedback regarding provisions for customer disputes.

Originally, Allegheny's tariff would have held that disputed amounts would be withheld from the supplier until the customer notified Allegheny that the dispute has been settled. Under the proposed revision, Allegheny would release disputed amounts if the customer, Maryland PSC, or supplier informs Allegheny that the dispute has been resolved. If the supplier informs Allegheny of such resolution, it must warrant that the dispute has been settled, and the amount released may be withheld again (deducted from future receivables) if Allegheny is subsequently informed that the dispute was not resolved.

The Retail Energy Supply Association said that Baltimore Gas & Electric, Pepco and Delmarva should institute a similar provision.

RESA also noted that Pepco, Delmarva and Allegheny would only withhold "the disputed amount" from the supplier. BGE, however, would withhold all monies - including non-disputed amounts in subsequent bills - from the supplier going forward until the dispute is resolved. "BGE's language is heavy-handed and should be modified to address only the dispute in question," RESA said.

RESA said that the cost recovery riders used to recover POR implementation costs are misnamed at BGE, Pepco and Delmarva, as the riders recover more than just POR costs. The rider would be called Rider POR at Pepco, and the Electric Choice Charge at BGE. RESA noted that the Pepco rider would include uncollectibles associated with SOS. The BGE rider would also include charges beyond those associated with POR, RESA said, and paints a negative picture of customers having yet another charge on their bill, this one named for electric choice. RESA recommended using Allegheny's term for the rider, Societal Benefits Charge, at all utilities.

However, the Maryland Energy Administration opposed the use of the term Societal Benefits Charge at Allegheny, as it argued the term usually connotes energy efficiency or other social programs. POR, the Maryland Energy Administration argued, will principally benefit suppliers in marketing their energy products to consumers. MEA favored using BGE's Electric Choice Charge name instead.

MEA also opposed BGE's attempt to earn a return on POR activities. MEA noted that the utilities earn an administrative charge for executing their role as the provider of last resort that includes a return component, and said the collection of supplier accounts receivables is arguably an extension of that role.

RESA asked that POR be extended from its current basic supply service limitation to include demand response and renewable energy products. The current definition could prevent suppliers from recovering the costs of RPS compliance, RESA noted.

## NUS Asks Md. PSC to Reclassify Potential Penalty

NUS Consulting, which had operated as a broker in Maryland for some three years before receiving a license earlier this month, asked the PSC to reclassify any potential civil penalty against the broker as a "voluntary assessment/payment."

As only reported by *Matters* (Matters, 7/3/09), the PSC approved NUS's license last week, and ordered it to pay $139.61 for unpaid Commission assessments for the period it had been operating in the state. While Staff had recommended a civil penalty of $1,039.61 against NUS, the Commission said it would take the penalty under advisement for the time being.

NUS said that while it had been brokering contracts since April 2006, no supplier advised it of any requirement to apply for such licensing until July 2008. "In those states where NUS previously applied for broker licensing, it was the generation suppliers who had provided notice to us of such requirement," NUS said.

"We are sure the Commission can appreciate the ramifications any civil penalty carries for a company wanting to conduct future business in any other state. Accordingly, we respectfully request that the Commission consider a reclassification of NUS' civil penalty as some form of a voluntary assessment/payment in order to avoid scandalizing an otherwise reputable and professional organization that has served the business community for over 75 years," NUS said.

## Pa. PUC Updates Capped, Market Price Comparison

The Pennsylvania PUC released its latest comparison of currently capped rates versus recent market prices. The expected increases in most service areas have grown slightly since the March comparison, but are still well below projections from last summer:

**Increase from Capped Rates**
**Residential**

| | Met-Ed | PECO | Penelec | PPL | Allegheny |
|---|---|---|---|---|---|
| 6/30 | 26.4% | -4.6% | 22.0% | 17.0% | 14.2% |
| 3/30 | 22.7% | -7.4% | 15.9% | 11.0% | 7.3% |

**Commercial**

| | Met-Ed | PECO | Penelec | PPL | Allegheny |
|---|---|---|---|---|---|
| 6/30 | 29.6% | -9.6% | 21.8% | 21.1% | 13.6% |
| 3/30 | 25.4% | -13.1% | 14.0% | 13.4% | 6.2% |

**Industrial**

| | | | | | |
|---|---|---|---|---|---|
| 6/30 | 27.9% | -6.8% | 25.4% | 17.6% | 16.6% |
| 3/30 | 24.7% | -10.0% | 18.3% | 11.4% | 10.3% |

The PUC also provided a comparison between capped rates and rates at PPL and Allegheny based on procurements conduced to date (rather than solely market pricing).

At PPL, residential rates are expected to increase 30.4% based on procurement results to date. Small commercial rates are projected to increase 18.9% while mid-sized businesses are projected to see a 36.8% increase.

At Allegheny, residential customers are projected to see a 10.6% increase (the PUC did not make projections for other classes as fewer supplies have been bought for those classes).

## *Briefly:*

### DPUC Opens Docket for LDC Code of Conduct

The Connecticut DPUC opened docket 09-07-02 for the promulgation of regulations to establish a code of conduct for the transactions between natural gas distribution companies and their affiliates.

### Texas-based Freedom Group Under New Ownership

Texas-based Freedom Group, LLC (d/b/a Freedom Power) has been acquired by CIB Irrevocable Trust, it reported in an amendment to its REP application. Freedom said its management team remains the same.

### CAISO to Hold Renewable Forum

The California ISO will host a Renewable Energy Issues Forum on July 21 to discuss the challenges associated with reliably integrating green power. The Renewables Issues Forum will consist of three panel discussions: (1) Policy considerations related to a 33% renewables mandate, (2) technology and market solutions for reliable grid operations, and (3) planning opportunities and challenges associated with renewable resources.

## *PPL ... from 1*

default service, with a prohibition on shopping until the arrearage is paid off.

RESA noted that generation-related uncollectibles are recovered in PPL base rates, and thus said including supply uncollectibles in a POR discount rate would recover such costs twice from migrated customers.

OCA insisted that the POR discount should reflect incremental supplier uncollectible expenses, plus administrative costs. Additionally, no further unbundling of base rates should be implemented if POR is introduced, OCA said.

The consumer advocate supported the Tentative Order's provision that POR would only cover basic supply service, excluding renewable generation and complex products. RESA said that all generation service, including renewable generation, should be covered under POR, but agreed other services, such as appliance contracts, should be excluded. However, utilities should still be required to bill such services on consolidated bills, RESA said.

OCA argued that utilities should not be permitted to terminate customers for failure to pay charges above the cost of default service, and said that under POR, suppliers should not be permitted to screen customers based on credit, or require security deposits.

OCA also rejected the notion that POR would appreciably increase choice to residential customers, arguing that Duquesne Light has not see a measurable increase in residential competition since the introduction of POR.

Allegheny Power said that the Tentative Order's provision allowing for cost recover of POR implementation costs, and the authority to disconnect customers not paying competitive charges, has led it to change its opinion of POR, and it does not oppose POR under such conditions.

**Other Issues**

Aside from POR, OCA expressed concerns that other provisions of the Tentative Order could have the impact of "significantly burdening" customers with higher costs with no discernible benefit.

The PP&L Industrial Customers Alliance also raised cost recovery concerns.

The industrial alliance further said that the "majority" of competitive suppliers have been "unwilling or unprepared" to provide indicative or bidding quotes to industrials for the first half of 2009. While pricing activity has since picked up, waiting until July, August or September to execute 2010 supply contracts could cost customers additional money if market prices increase, industrials said. The industrial coalition said it was "disappointed" with the response from suppliers, given suppliers' assurances at the Commission that they would meet the needs of large customers. The alliance suggested that adopting the reforms contained in the Tentative Order may further delay competitive offers, as suppliers hold out for the reforms to be enacted before offering quotes to customers.

Direct Energy Services said that suppliers need about four months of rules certainty to put their systems in place and make other arrangements to fully enter the PPL market. Accordingly, Direct asked that the Commission conclude the proceeding (including any reconsideration requests) by its August 27 meeting, with a final order issued at the July 23 meeting.

The Tentative Order would require PPL to offer both rate ready and bill ready billing, with rate ready supporting a minimum of fifty rates per customer across rate classes. OCA was concerned about requiring fifty minimum rates absent a cost-benefit analysis, while Allegheny said there should be a time limit on how long utilities are required to maintain rates that are not being used by suppliers.

Agway Energy Services, Gateway Energy Services Corporation, Interstate Gas Supply, and Vectren Retail, filing as the Energy Marketing Group, argued that a, "significant number of separate and discrete rates per customer across each rate class are critically important."

"While fifty separate rates per classification may seem like a large number, it has been our experience that these placeholders are used rapidly during changing market conditions," the four marketers said.

RESA and the Energy Marketing Group both recommended that PPL offer a customer referral program similar to programs in New York and Connecticut, with the Energy Marketing Group arguing that any referral program should include a "warm transfer" of interested customers to eligible energy suppliers' call centers. RESA suggested that PPL be ordered to include information provided by competitive suppliers in PPL mailings, with suppliers paying a share of incremental postage costs.

The Tentative Order would permit suppliers to obtain historical usage of prospective customers without manually submitting an authorization to PPL. RESA said that the authorization process should not require customers to use their account number, which many customers do not know without consulting their bill, and should rely on various other customer identifiers (name, SSN, address, etc.). Direct Energy said that obtaining customer information should be an automated process that is not time consuming for suppliers.

Constellation NewEnergy suggested specific timelines for various EDI usage information transactions, recommending that:

• Monthly Usage 867 data should be provided within 3-5 business days of a meter read;

• Responses to EDI requests for scaler-level Historical Usage data should be provided within 2-3 business days; and

• If applicable, the transmission and distribution invoice detail (i.e., 810 data) should be provided at the same time that Monthly Usage 867 data is provided to a supplier.

While the Tentative Order would allow PPL to provide suppliers with a customer's meter read cycle information in either an 814 enrollment response transaction or an 867 Historical Usage transaction, RESA said the meter read cycle data should be provided with the Historical Usage transaction. Otherwise, suppliers will not receive the meter read cycle information until enrollment has already begun, meaning they cannot use the information in developing pricing or determining when to submit an enrollment.

## Conn. ... *from 1*

side on a competitive basis. CL&P opposed any requirement for a competitive RFP, claiming that a mandated RFP process could deprive consumers of benefits from bilateral arrangements that utilities may encounter outside the RFP process.

Furthermore, while the DPUC would require utilities to separate "buy" and "sell" teams in contract solicitations to prevent affiliate abuse, CL&P said such a restriction is not necessary in non-competitive bilateral negotiations, even where a counterparty to the contract may be a utility affiliate.

PSEG Energy Resources & Trade, however, said that not only should separate buy/sell teams be used, the DPUC should prohibit employees from working on both teams, or moving between the teams (the procedural order would allow some movement between the teams for good cause). NRG Energy went further, recommending that a utility not be permitted to contract with an affiliate (though the affiliate could compete in its non-native service areas). Constellation Energy also opposed allowing utility affiliates to participate in bidding.

Although CL&P tested the market late last year, it conceded that, "The potential bargains CL&P, the Department and others had initially hoped for have not materialized."

Still, CL&P said that it hopes to see savings in a new solicitation for energy-only contracts for the period 2011-2015. CL&P is seeking energy-only contracts because it does not anticipate any capacity savings available under bilateral contracts due to the nature of the Forward Capacity Market. CL&P said it selected 2015 as the end date as most suppliers are not willing to provide pricing beyond that date.

However, in the longer-term, CL&P continues to evaluate other bilateral options, including its parent's proposed joint venture with Nstar to import power from Hydro-Quebec, as well as bundled contracts with renewable generators.

Wholesale suppliers petitioned the DPUC for expedited review of any contracts submitted. CL&P asked that medium-term (up to five years) energy-only contracts be approved on the same day that they are submitted, to reduce risk premiums, though it proposed a four-month review for contracts procured outside of an RFP.

PSEG Energy Resources & Trade said that the DPUC must recognize that if bidders are expected to hold their pricing firm until completion of an open-ended review process as suggested in the procedural order, suppliers will either include significant risk premiums in their bids or, at worst, elect not to participate in the bid process at all. PSEG Energy Resources & Trade suggested an approval timeline similar to that used for the full requirements contracts procured for default service.

NRG Energy suggested that the DPUC implement a five-day evaluation of bids, or, alternatively, that suppliers be allowed to adjust their pricing based upon an appropriate index or other appropriate mechanism if the evaluation period will extend beyond five business days.

Most wholesale suppliers also opposed the DPUC's intent to release the winning supplier's name and price upon awarding the contract. Constellation Energy warned such disclosure would chill bidding, and Brookfield Energy Marketing agreed that the information should be kept confidential.

NRG Energy noted that a plant's total capacity may not be procured under the DPUC approved contract, meaning that releasing the supplier's name and bid price would disadvantage the supplier in negotiating the sale of its remaining capacity with other buyers. The DPUC could release either the winning bidder's name, or the price, but not both, NRG said.

Towantic Energy, which is developing a 500 MW gas-fired plant it claimed would benefit ratepayers, opposed allowing the distribution utilities to limit their RFPs to certain terms. Specifically, United Illuminating's most recent solicitation prohibits the pass-through of changes in natural gas prices. Despite its contention that its plant would save ratepayers hundreds of millions of dollars, Towantic said that it is not economic for developers to bear the commodity price risk for periods longer than five years.

Brookfield Energy Marketing urged the DPUC to require that proposals that are dependent on participant funded transmission lines to clearly identify all transmission related costs included in their proposals (taking square aim at the arrangement between CL&P parent Northeast Utilities, Nstar and Hydro-Quebec).

NRG similarly urged the DPUC to consider whether a proposed project relies upon the construction of transmission resources that have yet to be fully-permitted or approved. "In other words, the value of a project's certainty of completion must be considered, and one which relies on completion of as-yet-unpermitted transmission would place an inordinate risk on ratepayers if the project/contract ultimately is not able to deliver its purported benefits to ratepayers," NRG said.

The DPUC procedural order said that renewable projects would have their environmental benefits considered in the contract review in addition to price and other commercial terms. NRG asked that similar treatment be extended to all types of plants, as some non-renewable resources may be priced to include emissions controls, while competing non-renewable projects may lack such controls and thus reflect a lower cost.

NRG further said that the Department should not allocate all 20% of the bilateral contract carve-out to a single supplier, to diversify risk.