Energy Choice Matters
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Delmarva Files Maryland POR Discount Rate, BGE Files Calculation But Not Rates

Delmarva Power filed a Maryland purchase of receivables compliance plan that would set the initial discount rate for Schedules R, R-TOU-ND, and OL at 1.71%, reflecting uncollectibles of 1.06%, incremental costs of 0.43%, and a risk factor of 0.22%.

The risk factor represents, "the risk associated with the continuation of the supplier-customer relationship," and is set at one-half of implementation costs. Delmarva noted that should a large number of customers migrate to dual billing, recovery of implementation costs would be at risk. In light of this risk, Delmarva's tariff would allow it to directly charge suppliers for the costs of the program and uncollected receivables if there are insufficient suppliers using consolidated billing. "This will avoid imposing costs of the purchase of electricity suppliers' receivables on customers, while imposing the costs and risk of the service on suppliers."

The volume of receivables will be determined to be too low to recover if the unrecovered costs in a reconciliation component rise above 1%. The reconciliation component will be calculated as, by customer grouping, the imbalance (difference between cumulative costs eligible for recovery and discount amounts for purchased receivables) plus interest, divided by the estimated electricity revenues billed for all electricity suppliers for each customer grouping.

Delmarva will review the level of the risk discount after a year of experience with the POR program.

For Schedules SGS, TN and ORL, the discount would be 0.98%, reflecting uncollectibles of 0.33%, with the same discount percentage as for residential customers for incremental costs and the risk factor, which are constant across all classes. For Schedules LGS-S, GS-P and GST, the discount would be 0.75%, reflecting an uncollectibles rate of 0.10%.

The uncollectible expense component in the discount rate is calculated by dividing estimated

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Pa. Working Group Files Report on Rate Ready Billing at PPL, PECO

Six rate components would be available to competitive suppliers under rate ready billing at PPL under consensus recommendations from suppliers, electric distribution companies, and EDI service providers which were filed with the Pennsylvania PUC by the Electronic Data Exchange Working Group (M-2009-2104271).

In its August order on removing barriers to competition at PPL, the PUC directed PPL to work with stakeholders via the Electronic Data Exchange Working Group so it could implement rate ready billing. PPL and PECO are the only two Pennsylvania electric distribution companies which do not offer rate ready billing. PECO also participated in the working group, though it believes the PUC's order to implement rate ready billing is limited to PPL.

In the working group, suppliers and distribution companies agreed on the "rate code" method of rate ready billing, whereby a supplier utilizes a minimum of three alphanumeric characters to define a rate code. That differs from the price-driven model of rate ready billing which does not utilize a rate code, and rather depends only upon the price(s) specific to each customer account.

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III. Power Agency Revises Long-Term Renewable PPA Proposal, Requests 20-Year PPAs

The Illinois Power Agency (IPA) has filed to amend its procurement plan currently pending before the Illinois Commerce Commission to specify that the proposed long-term contracts for renewable energy would be for 20-year terms, and would be for bundled energy and RECs (Only in Matters, 10/2/09). Due to these revisions and other clarifications (regarding the cost caps on RPS compliance), Commonwealth Edison said it no longer objects to the long-term renewable procurements.

The volume to be purchased on long-term PPAs would remain unchanged -- 3.5% of the portfolio, as only reported by *Matters*. That translates into 2 million MWh annually over the 20-year period, or a total purchase of 40 million MWh.

"Having considered the need to hedge carbon risk, the opportunity to capture consumer benefits by procuring Long-Term PPAs at a time when unprecedented federal and State incentives are available to renewable energy producers, and the potential uncertainties associated with variable generation and interconnection costs, the IPA finds that two million MWh is the appropriate near-term target for this planning cycle," the Illinois Power Agency said. As before, the 2 million MWh annually would be split as 1.4 million MWh at ComEd and 600,000 MWh at Ameren.

Clarifying its earlier plan, the power agency said that purchases would be for bundled energy and RECs. Capacity would not be included, and generation owners would retain the capacity value of the asset as well as any RECs not associated with the purchased generation.

The procurement would be open to both existing and new generation.

The amendment clarifies that prices for the long-term PPAs would be set through the IPA's competitive RFP process, where the contract terms will be standardized and winning bids will be selected on the basis of price alone.

The REC portion of the procurement will count toward the RPS requirements and comply with the bill-impact cap set forth in Section 1-75(c) of the Illinois Power Agency Act. The procurement will also, to the extent available, procure at least 75% of the renewable energy from wind, with statutory cost effective tests and locational preferences also applied. Still, all resources that qualify as renewable energy resources under the Illinois Power Agency Act are eligible to submit offers in the procurement.

The terms of the PPAs would allow for the delivery of energy through a fixed for floating financial swap. The fixed price for the swap will be the full bundled contract price for the renewable PPA. The floating price will be the Locational Marginal Price at the utility's load zone for each hour in the day-ahead market of the applicable Regional Transmission Organization.

The sellers of renewable energy will be required to commit a minimum quantity of energy and RECs to the utilities, while having some flexibility in managing their deliveries in order to limit the risk premium.

ICC ALJs Would Establish Workshop for North Shore, Peoples Gas Choice Issues

A proposed Illinois Commerce Commission decision would defer consideration of all small volume customer choice issues in North Shore Gas' and Peoples Gas' rate cases to a workshop process, due to the lack of a complete record in the proceeding (09-0166 et. al.).

As only reported in *Matters*, several retail suppliers petitioned for changes in the allocation of administrative costs, the enrollment window, and single billing logistics (Only in Matters, 6/12/09). Dominion Retail, Interstate Gas Supply, and Nicor Advanced Energy jointly filed testimony in the cases.

Two ALJs found that the retail suppliers provided "compelling evidence" to show that the North Shore/Peoples' Choices for You (CFY) program is not functioning as well as it could, noting migration of only 3%. "While it is clear that changes to the CFY program are needed, nothing more of clarity appears on the record," the ALJs found, noting that the suppliers favor the wholesale adoption of the program recently approved by the Commission for Nicor.

"Whether this would be appropriate for the Utilities' choice program is not known because the Utilities chose not to seriously respond to [suppliers'] proposal. Accordingly, we are left with an incomplete record," the ALJs said.

"The Commission cannot order wholesale changes without a complete discussion of the particulars and an analysis that explains what we are being asked to adopt. Thus, Staff's proposal to hold workshops is the only reasonable option of record to address the CFY program," the ALJs said, in proposing that all of the issues raised by suppliers should be addressed in the workshop.

Chief among these issues is the allocation of LDC-owned storage, transportation and related assets. Suppliers argued that 93% of the LDCs' sales customers' peak day demand can be satisfied by the company-owned assets, while choice suppliers, due to their limited rights, can only satisfy 71% of their customers' peak day demand. Suppliers offered various solutions such as releasing assets to follow the customer during migration, providing expanded rights, greater flexibility and wider tolerances for deliveries and injections similar to Nicor, or reducing costs allocated to choice customers through the Aggregation Balancing Gas charge in recognition of the lower value they receive from the assets.

Suppliers also sought to modify the administrative charge included in the Rider AGG Aggregation Charge and the LDC Billing Option charge billed to suppliers on a per-customer basis. Currently, only suppliers (and their customers) pay the administrative charges related to choice, with sales customers not paying any such administrative costs. Suppliers argued that the LDCs have not shown that there are any incremental costs related to choice to justify the charges. Even if there are such costs, suppliers said that all customers eligible for choice should be assigned those costs through base rates, similar to Nicor.

The competitive suppliers also opposed the LDCs' implementation of the rescission period under SB 171, which sets the period at 10 business days. The LDCs filed for an enrollment window of 19 calendar days in recognition that a switch submitted on November 25, 2009, must wait 19 calendar days before the switch can legally occur, due to holidays and weekends pushing out the date by which the utility sends the enrollment notice, and then the days included in the 10 business-day rescission period.

Suppliers further argued that new service customers should be allowed to elect a competitive supplier at service initiation, and not be required to take a minimum period of sales service before switching.

Regarding supplier-consolidated billing (the single billing option - Rider SBO), suppliers had two requests. First, the suppliers argued that customers in payment arrears to the utilities should not be removed from receiving a Rider SBO bill. Second, any credit owed to the customer from the utility when a customer switches to Rider SBO should automatically flow to the supplier to be applied to the customer's account, rather than cutting a check to the customer, and requiring the customer to then remit their normal deposit or payment to the supplier.

Suppliers also requested that the LDCs should state inventory or storage volume information on the monthly bill. All the issues cited above will be addressed in the workshop, under the draft order.

Transportation Service

Aside from several issues previously agreed to by parties (see Matters, 7/14/09), the ALJs addressed a remaining transportation service issue -- Constellation NewEnergy's request for super pooling.

Specifically, Constellation argued that the LDCs should permit super pooling on critical days, which allows all third party groups, or pools, that are under common management to be balanced in aggregate prior to the application of unauthorized usage charges. A Critical Day is either a Supply Surplus Day or a Supply Shortage Day.

The ALJs agreed that super pooling is reasonable, and that a supplier should be able to have its penalties changed when it can show that its other commonly managed Rider 13 Groups' critical day deliveries would have eliminated the Unauthorized Use condition in whole or in part. The ALJs found that because the LDCs suffer no harm on critical days when a supplier's usage overall complies with the LDCs' rules, no penalties should be assessed.

The proposed decision would also affirm commitments made by the LDCs earlier in the case, including rounding Maximum Daily Quantity (MDQ) for Choices For You customers to the nearest therm rather than the current nearest dekatherm, for greater accuracy for low volume customers.

The LDCs will also offer a new late nomination (Evening Cycle Nomination) as a compromise in response to Constellation's request for four nomination cycles. For a four-year trial period, the LDCs will offer the Evening Cycle Nomination, under which the supplier must make the nomination no later than 3:00 p.m. on the business day prior to the gas day on which it is to be effective. Unlike timely nominations, which are available every day, the new Evening Cycle Nomination would only apply to nominations on business days. The LDCs, by 2:00 p.m., would post on their PEGASys system the aggregate volume that the Evening Cycle Nomination may not exceed. Except for Critical Days, the minimum quantity available (increases and decreases) would be 100,000 therms for Peoples Gas and 20,000 therms for North Shore. On Critical Supply Surplus Days, the LDCs will allow no increases. On Critical Supply Shortage Days, the LDCs will allow no decreases.

Sempra Reports Strong Interest in Replacing RBS in Commodities JV

Sempra Energy has already received strong interest from a wide range of players in replacing The Royal Bank of Scotland in the RBS-Sempra Commodities joint venture, Sempra CEO Donald Felsinger reported during an earnings call.

RBS is being required to sell its stake in the joint venture as a condition of receiving European state assistance (Matters, 11/3/09).

During an earnings call, Felsinger said that Sempra will "absolutely" stay in the commodities business, and would revert the business back to a stand-alone entity if need be.

However, executives said that such a process is unlikely, as Felsinger described an "amazing" response in just about a week since RBS' announcement. Aside from the expected financial institutions, executives reported that they have received interest in the commodities joint venture from large physical/industrial and oil firms, and sovereign wealth funds.

Given such interest, executives said that a replacement for RBS could be completed "sooner rather than later" in reference to a four-year deadline imposed on RBS by the European government. A quicker transaction would allow Sempra to take advantage of any opportunistic timing that may present itself, and align itself more quickly with a partner focused on growth, rather than one operating under constraints.

Felsinger noted that, regardless, RBS is committed to providing all required capital and credit support through its exit, which will be orderly and significantly influenced by Sempra which has a first offer right.

Sempra reported $75 million in earnings from its share of RBS-Sempra Commodities for the quarter, reversing the year-ago loss of $8 million, with the strong results driven by performance in natural gas and metals. Distributable income from the joint venture was $83 million for the quarter.

Sempra Generation reported lower earnings of $43 million, compared with $94 million a year ago, on weaker power prices and the absence of mark-to-market gains recorded in the 2008 quarter.

Calif. PUC Opens Proceeding on Direct Retail Customer Participation in CAISO Markets

The California PUC yesterday issued a scoping ruling to institute a new phase of R. 07-01-041 to address the direct participation of retail customer demand response in the California ISO and related issues raised by FERC Order 719. Among other things, the case is to address the current limit of one scheduling coordinator per meter.

The scoping ruling begins the PUC's effort to determine whether existing state procurement laws, decisions, rules or practices may directly or indirectly conflict with potential direct bidding by retail demand response into CAISO wholesale markets. "This review of state statutes and rules should not be viewed as an effort to forestall the expansion of such Demand Response activities but, rather, as a process to identify and expedite resolution of the complex issues raised by the FERC's proposed changes to California's energy markets," the PUC said. FERC Order 719 permits retail customers to bid demand directly into the wholesale markets unless prohibited by the relevant retail regulator.

"It has been suggested that to allow aggregators to represent retail load in CAISO energy markets, the CAISO must remove tariff language that prohibits more than one Scheduling Coordinator per customer meter," the PUC noted. "The Investor Owned Utilities (IOUs) subject to the California Public Utilities Commission (CPUC) jurisdiction each have retail tariff provisions that may be interpreted as barring use of more than one Scheduling Coordinator per customer," the Commission added.

For example, Pacific Gas and Electric's Tariff Rule 22 reads in part, "As a requirement of this tariff, [Energy Service Providers, or ESPs] providing electric power shall have one or more Scheduling Coordinators, with no more than one Scheduling Coordinator per service account, for the purpose of reporting all of the ESP's end-use meter readings to the Independent System Operator (ISO)."

Among a series of questions, the PUC asked that, "[i]f such current tariffs, rules, or procedures are changed or eliminated, is there need for other rules to provide protections to Load Serving Entities, consumers, other market participants, or to otherwise maintain the integrity of CPUC [demand response] programs."

The use of multiple Scheduling Coordinators per meter can cause double procurement in the absence of appropriate communication protocols, the PUC observed. For example, a Load Serving Entity may purchase energy to meet expected customer demand, while the Demand Response provider sells that same customer's Demand Response load into the wholesale market. If the Load Serving Entity is not notified of the Demand Response provider's actions, it will procure to meet the customer's full expected load rather than the reduced load reflecting the dispatch of Demand Response. "Such double procurement raises consumer costs, and may impede California's Loading Order preference for relying upon Demand Response resources instead of traditional fossil-fuel generation to fulfill load if generation is dispatched rather than the Demand Response," the PUC said.

The absence of appropriate communications can also create payment/settlement confusion arising from having two Scheduling Coordinators for the same meter. Having two Scheduling Coordinators raises questions about who pays whom for the shed load and for the energy procured to meet that load – issues previously raised by competitive suppliers at CAISO.

The PUC also asked how it can minimize potential gaming opportunities related to direct customer participation in wholesale demand response.

Briefly:

Suppliers Could Require Proof of Eligibility for Termination Fee Waiver Under Revised DPUC Draft

The Connecticut DPUC has issued a revised draft decision regarding Dominion Retail's petition for a declaratory ruling on Conn. Gen. Stat. §16-244c(k)(5), relating to the prohibition of termination fees and the supplier referral program (09-04-40, Only in Matters, 10/26/09). The draft's findings are not substantively changed, and, as only reported in *Matters*, the Department would find that the termination fee prohibition only applies to customers in the referral program who switch to another supplier in the program, or back to Standard Service. It would not apply to customers not in the referral program. As in the earlier draft, the Department would find that termination charges would not be prohibited if a referral customer switches from a supplier in the referral program to a supplier that is not in the referral program. The revised draft adds a provision that, in order for the customer to take advantage of the termination fee prohibition, "a customer may be required by the serving provider to demonstrate that the customer is switching to standard service or to another Participating Electric Supplier." The draft does not expound on what evidence suppliers could require of customers under this provision.

Judge Dismisses Suit Against Stream Energy

A U.S. District Court Judge dismissed a class action lawsuit brought against Stream Energy by two former sales agents, finding that the agents must settle any dispute through arbitration as stated in their contracts. The agents had alleged Stream's network marketing model was a pyramid scheme (Matters, 7/2/09).

Frontier Utilities Seeks to Add Two Trade Names

Frontier Utilities applied at the PUCT for an amendment to its REP certificate to add the trade names Sol Energy and Rodeo Energy.

PUCT Approves REP Certificate Amendment Recognizing Abacus Resources Energy's Purchase of Always' Certificate

The PUCT approved a REP certificate amendment reflecting Abacus Resources Energy's purchase of the certificate of Always Electric (Only in Matters, 9/30/09).

NRG Acquires Bluewater Wind

NRG Energy has acquired Bluewater Wind, which, among other things, has a 25-year, 200-MW PPA with Delmarva Power to provide supply to Delmarva's Delaware customers from an offshore wind project. NRG purchased Bluewater from Babcock & Brown and Arcadia Windpower with cash on hand, for an undisclosed sum. Bluewater's existing development team will become NRG employees, working out of Bluewater's office in Hoboken, NJ. The company's President and founder, Peter Mandelstam, will remain President of Bluewater Wind and also serve as head of NRG's offshore wind development efforts.

Comverge Narrows Loss

Comverge reported a narrowed net loss of $9.4 million for the third quarter, compared to a net loss of $81.8 million a year ago. As of September 30, 2009 total megawatts under management were:

- Megawatts under long-term contracts with regulatory approval 919
- Megawatts under open market programs 1,181
- Megawatts to be provided under turnkey programs 320
- Megawatts managed for a fee 437
- **Total megawatts 2,857**

DPUC Issues Report on Licensing

The Connecticut DPUC issued a draft repot in docket 09-10-11 providing a cumulative review of the number of electric suppliers (3) and aggregators (8) that have been licensed in 2009.

Md. POR ... from 1

electric supplier uncollectible expenses associated with each rate schedule by the electricity revenues billed for all electricity suppliers for that rate schedule.

Delmarva also said, on a one-time basis, it will purchase 100% of currently billed receivables yet to be paid by customers on December 7, 2009, the effective date of the POR program, for customers on utility consolidated billing. Delmarva said that such action is required to reduce customer confusion during the transition to POR. "If the Company does not purchase the receivables for this period, then the customer may pay the full billed amount, however, due to the transition, the full payment will be held by the Company after December 7, 2009 and the supplier will not be paid. The supplier in turn may issue a separate bill for that amount," Delmarva said.

However, delinquent balances purchased at 100% will be returned to suppliers for collection. Effective with 810 charges received on and after December 7, Delmarva will begin purchasing the current balance with each bill, at the discounted rate.

Baltimore Gas & Electric also filed a compliance plan to calculate its electric POR discount rate, but did not submit the actual rate yet. BGE, which plans to have POR operational for April 1, 2010, would file the discount rates by December 31 of each year.

Two discount rates would be established, with customers divided into two groups: Residential - Schedules R, RL-1, RL-2 and ES; and Non-Residential - Schedule G, GS, GL and P. The discount rate would include: (1) uncollectibles, (2) program development costs, (3) operational costs, and (4) a flat 1.25% risk factor, to be paid to BGE for retention by its shareholders to compensate them for the risk associated with the continuation of the supplier-customer relationship.

BGE will also be able to directly charge suppliers for implementation costs should participation in POR decrease, in a manner similar to Delmarva. BGE would use essentially the same reconciliation and imbalance factor calculations as described for Delmarva.

BGE also revised its tariff to reflect the PSC's finding that while the customer has the choice of billing options, the electricity supplier is not required to offer any specific billing option to customers. To reflect this, BGE revised Section 12.1 of the Coordination Tariff to state:

"A Supplier must elect the Electric Company Consolidated Billing option or, alternatively, the Dual Billing and/or Supplier Consolidated Billing options, if available, for all its customers within a rate class. If a Customer within that rate class does not wish to be billed using the option selected by the Supplier, and communicates that to the Supplier, that Customer may be billed as requested."

Pa. Rate Ready ... from 1

Given the distribution companies' billing system limitations, a consensus developed around permitting six rate components under rate ready billing:

- Usage (kWh) charge only (No Proration)
- Demand (kW) charge only (No Proration)
- Flat fixed monthly charge (No Proration)
- Any combination of Usage, Demand, and Flat fixed monthly charge
- % of default service rate (Must be flat POLR rate; % could be either a premium or discount to the POLR rate)
- Flat fixed monthly charge, plus % of default service rate (Must be flat POLR rate)

The rate components are intended to mimic simple fixed rate structures using standard pricing components. Structures relating to blocking or to any complex rates that vary based on other parameters will not be offered. Stakeholders reached consensus that suppliers who wish to implement more complicated rate designs should exercise their option to utilize either bill ready utility consolidated billing or dual billing.

Stakeholders agreed that the distribution companies will provide the supplier with a minimum of a three-character alphanumeric rate code which will allow for a substantial number of distinct and separate rates, with up to five decimal place precision on each pricing component. Supplier rate codes will not be utility rate class specific. The distribution companies will not remove unused rate codes without consent of the supplier.

The supplier charges on the bill for a particular customer's account will be based upon the rate code provided by the supplier on either the EDI 814 Enrollment transaction or the most recent EDI 814 Change transaction associated with the customer's account. The utility will reject enrollments for rate codes not previously established in the utility's systems.

Stakeholders agreed that distribution companies will provide the supplier with the capability to switch between bill ready, rate ready and dual bill billing options by submitting changes via EDI 814 Change transactions. Distribution companies differ on how they handle the effective date of the Change transaction, the working group noted, suggesting that additional discussion of a statewide effective date may be warranted.

Distribution companies will not limit the number of supplier rate code changes. The last change processed will be the effective rate code. Requests to change the supplier rate code on a particular account must be processed in 14 calendar days or preferably less. The rate code must be validated in the utility's system prior to the Change request being submitted, and invalid codes will be rejected.

The distribution companies will implement an automated approach to rate code creation and maintenance. PPL will explore providing a website interface for the supplier to use to establish new rate codes or to update price information on existing rate codes. PECO will explore the use of EDI to fulfill this same task, but will analyze both EDI and website system approaches.

The number of rate codes a supplier will be able to add to those retained by a given utility at a particular point in time will depend on the solution that the utilities will to implement new rates.

Requests to change the pricing components associated with an existing supplier rate code on a particular account must be processed in 14 calendar days or preferably less. Distribution companies will not limit the number of supplier price changes on a rate code. Suppliers will not be able to add or remove pricing components of an established rate code; a new rate code would be required.

The distribution companies will list on bills each pricing component associated with the supplier charges for a particular bill period as a separate line item, with a total and the associated breakdown. Suppliers and utilities agreed that the utility will use the tax exemption percentage provided by the supplier on the 814 Enrollment/Change transaction to calculate sales tax for the supplier portion of the bill. Each tax calculated by the utility will be included separately on the rate ready 810 transaction sent to the supplier. A supplier is not required to submit tax exemption certificates to the utility.

PPL will perform budget billing for both distribution and supplier charges.

PPL estimated the cost of a fully automated rate ready billing system at approximately $1.3 million, and projected implementation of a fully automated system could be completed by the end of the third quarter of 2010. Should PPL be required to meet a shorter deadline than the proposed end of the third quarter of 2010, PPL will attempt to rollout a program that will have significantly limited capabilities compared to the consensus solution.

PECO initially estimated the system implementation cost of a fully automated rate ready billing solution (using a website rather than EDI for rate code maintenance) at $3.3 million, not including additional Sarbanes-Oxley controls, modified rate and price testing processes, back office impacts resulting from associated supplier rate ready billing disputes or additional call volumes, and other business impacts. PECO projected implementation would take 18 months. As noted previously, PECO does not believe the Commission has ordered any change from its existing default service settlement (which did not include rate ready billing), and continues to examine alternative implementation approaches to fulfilling the same rate ready billing requirements.

The Electronic Data Exchange Working Group noted that the group is best known for its "technical products," stating that its study of rate ready issues focused primarily on policy and business practices. "If the Commission is going to continue to request and require policy and business practice products like this from EDEWG, then EDEWG's technically-oriented mission may need to be adjusted," the group's report said.

The working group included Allegheny Power, Duquesne Light, the FirstEnergy utilities, PECO, PPL, ConEdison Solutions, Direct Energy, Dominion Retail, e:SO, Energy Services Group, FirstEnergy Solutions, Liberty Power, MXenergy, PPLSolutions, SJ Industries, Exelon Energy, Systrends and UGI Energy Services.