Energy Choice Matters

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Revised Draft Includes Same Effective Date for Texas Protections, Switch Hold Rules

An updated PUCT Staff proposed rule concerning disconnections and deferred payment plans would make rules expanding the eligibility of deferred payment plans effective on the same date on which REPs would receive authority to impose switch holds for those customers not meeting the terms of a payment plan -- June 1, 2011 (36131, Matters, 7/16/10).

Under the proposal for publication, the new customer protections would have taken effect December 1, 2010, while REPs' ability to disconnect customers for not meeting the terms of a payment plan would not have taken effect until June 1, 2011. The revised proposal harmonizes these dates.

Staff's latest language regarding pricing for customers subject to a switch hold whose term contracts expire provides that the REP may serve these customers under the lowest priced month-to-month product currently offered by the REP to new applicants, or at the price charged under the existing term contract that is expiring (on a month-to-month basis), or, if the REP does not offer month-to-month products to new applicants, the price equivalent to the lowest price of the shortest term fixed product currently offered by the REP to new applicants. Texas Legal Services Center has argued that the REP should be compelled to serve the customer at the lower of the lowest priced month-to-month product currently offered by the REP to new applicants, or the price charged under the existing term contract that is expiring.

As under the proposal for publication, REPs are compelled to offer deferred payment plans during extreme weather emergencies, disaster declarations, or when underbilling occurs. However, the revised Staff draft changes requirements governing proposed extended deferred payment plan

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Pa. Working Group Submits Rate Ready Billing Report

About two-thirds of competitive electric suppliers' Pennsylvania business plans would be "somewhat" or "greatly" adversely affected by the lack of a rate ready platform in every service territory, according to a poll conducted by the state's Retail Markets Working Group as part of a rate ready collaborative report (M-2009-2104271).

About 30 suppliers were solicited in the poll, and nine responded. PECO cited the lack of participation in the supplier poll as an indicator that implementation and/or uniformity of rate ready platforms is not entirely necessary.

Of the respondents, some 55% of competitive suppliers said that their business plans would be "somewhat" adversely affected by the lack of a rate ready platform in every service territory, while another 11% said that their business plans would be "greatly" adversely affected.

Furthermore, one-third of suppliers said that the lack of uniformity across all existing rate ready platforms hinders their operations greatly, while another one-third said that the lack of uniformity somewhat hinders their operations.

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FirstEnergy Ohio EDCs Suggest Moving July Load to October Auction

The initial competitive auction under the FirstEnergy Ohio utilities' proposed electric security plan for the period June 1, 2011 through May 31, 2014 must be held prior to the end of January 2011, the utilities said in testimony supporting the supplemental electric security plan stipulation (10-388-EL-SSO).

As only noted in *Matters*, the supplemental stipulation contains various changes, including some regarding governmental aggregation, which prompted the Northeast Ohio Public Energy Council (NOPEC) and Northwest Ohio Aggregation Coalition (NOAC) to sign the settlement (Only in Matters, 7/23/10).

The initial competitive procurement was to be held in July, but the Public Utilities Commission of Ohio has not yet ruled on the electric security plan, forcing the procurement to be held at a later date. The electric security plan calls for the creation of a three-year laddered procurement process.

The FirstEnergy companies recommended that the load that was to be procured in the initial auction, which is to procure 12-, 24-, and 36-month contracts, be combined with the auction scheduled to be held in October 2010. Alternately, the auction must be rescheduled to occur prior to the end of January 2011 in order to allow bidders the flexibility to engage in their individual hedging strategies through PJM's Auction Revenue Right/Financial Transmission Right (ARR/FTR) process that starts in early March 2011, the utilities said.

"If the rescheduled July 2010 auction doesn't occur prior to the PJM ARR/FTR process, bidders would be obligated to utilize the results of the Companies' ARR/FTR hedging strategy which would increase uncertainty and could increase bid prices in the auction," the FirstEnergy companies noted.

The FirstEnergy companies had originally applied to start procurements in July to take advantage of currently favorable market conditions.

In the supplemental testimony, the FirstEnergy companies also confirmed that they will not seek any phase-in of the new generation rates that result from the competitive auctions, though PUCO retains the right to order deferrals on its own motion.

NextEra Energy Resources Adjusted Earnings Flat

NextEra Energy Resources reported adjusted earnings of $195 million for the second quarter of 2010, flat versus $194 million a year ago. The adjusted metric excludes non-qualifying hedges and net Other Than Temporary Impairments.

GAAP earnings were slightly lower for the competitive energy segment at $163 million versus $154 million a year ago.

The contribution from wholesale marketing and trading was flat versus the year-ago. However, NextEra Energy Resources has raised its projected gross margin for its power supply business by $35 million since a first quarter estimate (to a range of $210-$230 million). Most of the growth is attributed to gains in the full requirements supply business, which is seeing more opportunities than expected earlier this year, as opposed to competitive retail growth.

For what NextEra termed larger transactions, more opportunities have arisen as the number of competing firms thinned last year through early this year. However, executives reported that recently a large, unnamed player that had appeared to pull out of the market last year has now jumped back in aggressively.

On an adjusted basis, NextEra Energy Resources' existing assets improved $4 million versus the year-ago quarter. Existing wind assets improved by $8 million driven by better wind resource and lower curtailments in Texas. Contributions from the NEPOOL portfolio improved by $8 million as well, owing primarily to higher-priced hedges at the Seabrook nuclear facility. These gains were offset by a negative $4 million performance from the Texas gas-fired facilities as a result of market conditions, and an aggregate negative $8 million variance in various other drivers NextEra did not deem notable to cite specifically.

NextEra Energy Resources has approximately 540 MW of new wind already in service, or in construction and likely to be commissioned in 2010. Based on the current state of its development pipeline, NextEra continues to believe that it will add between 600 MW and 850 MW of wind in 2010. For 2011, NextEra continues to plan to add 700 MW to 1,000 MW of wind generation.

Morris Energy Files Complaint Against PSEG Companies' MBR Authority due to Affiliate Retail Gas Rate

Morris Energy Group, LLC filed a complaint at FERC against PSEG Energy Resources & Trade LLC, and several affiliated companies, alleging that PSEG ER&T's failure to disclose a "preferential" retail natural gas rate received from affiliate Public Service Electric and Gas Company is grounds for the revocation of federal market-based rate (MBR) authority (EL10-79).

Morris Energy alleged that PSEG ER&T, through affiliates PSEG Power and PSEG Fossil, receives a "preferential" gas delivery rate from PSE&G of $0.425/dth, while independent power producers such as Morris Energy are served on Rate TSG-NF at $1.30/dth, for what Morris Energy called lesser quality service.

Morris Energy contended that the lower rate is not attributable to a threat of bypass, inferior service, or cost of service.

"This preferential rate violates the PSEG Power Companies' MBR authority and furthermore, the preferential rate was never disclosed in either the original MBR application or the updated MBR market power filings, notwithstanding the defendants' legal obligation to do so," Morris Energy alleged

"Therefore, the Commission should revoke the PSEG Power Companies' MBR authority until the affiliate rate is made available to all non-affiliated generators," Morris Energy moved.

Morris Energy further alleged that the PSEG Power companies engaged in "market manipulation" by relying on the preferential affiliate rate in a manner that Morris Energy believes, "has skewed, and continues to skew, the PJM dispatch order."

"If the Commission fails to take action, then other applicants for, and holders of, MBR authority may similarly fail to disclose affiliate preferences and unreasonable rates and terms imposed on non-affiliates. Such failure to take action may embolden other vertically integrated utilities to engage in similar conduct, thereby violating key tenets of the Commission's MBR program," Morris Energy said.

Morris Energy owns and operates nine electric generating facilities, totaling 850 MW of generating capacity in the Northeast U.S. Morris Energy owns four generating facilities located in PSE&G's territory, which purchase gas delivery service from PSE&G. Morris Energy's Bayonne and Elmwood plants purchase non-firm gas delivery service under PSE&G rate schedule TSG-NF, while Morris Energy's Camden and Newark Bay plants purchase gas delivery under individual gas supply contracts with PSE&G.

Morris Energy told FERC that, "[t]he discriminatory rate has contributed to Morris Energy exiting the PJM queue for planned generation plant expansions at the Bayonne and Camden facilities, while PSEG Power continues to pursue new gas-fired generating construction at their Kearney, NJ facility and completed construction of a new gas fired generator at their Linden facility."

Briefly:

PUCT Staff Links Interim TCOS, TCRF Effective Dates

PUCT Staff have submitted an updated proposal for adoption that would allow twice annual interim updates to transmission rates (37519, Only in Matters, 7/9/10). The revised recommendation makes the effective date of the rule contingent upon the effective date of potential amendments to Subst. R. §25.193 that allow a distribution service provider to recover, through its transmission cost recovery factor, all transmission costs charged to the distribution service provider by transmission service providers (which is being addressed in Project No. 37909). At the most recent open meeting, Commissioners had requested that the effective dates be harmonized.

FERC Revokes MBR Authority of Two Sellers

FERC revoked the electric market-based rate authority of Strategic Energy Management Corp. and Solaro Energy Marketing Corporation for failure to file electric quarterly reports.

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eligibility outside of these three conditions.

As under the earlier draft, REPs would have to offer certain vulnerable residential customers a deferred payment plan for bills that come due in July, August, or September, but now would only have do to so upon request. For bills that come due in January or February, REPs would have to offer vulnerable customers a deferred payment plan, only upon request, if the TDU recorded an extreme weather emergency for the residential customer's county for at least five consecutive days during the prior month. Under the prior draft, the trigger event for the extended deferred payment plan eligibility in January and February was whether ERCOT demand hit a winter peak, rather than consecutive days of a weather emergency.

The definition of vulnerable customers eligible for the extended protections enumerated above has not changed; however, stakeholders are examining the technical feasibility of expanding this group to include customers that are receiving support under the telephone Lifeline Service Program.

The updated draft grants REPs the authority to disconnect customers failing to meet the terms of a deferred payment plan without sending the customer an additional disconnection notice, if a disconnection notice is included on or with the bill.

The revised proposal also includes language that REPs are required to recite or provide in writing to customers, informing customers of the potential switch hold when the customer enters into a level or deferred payment plan whose terms include a switch hold. Consumer advocates wish to modify Staff's language to explicitly inform customers that under the switch hold customers, "will be giving up your right to buy electricity from other companies, even if a company offers you lower rates."

A copy of the customer's deferred payment plan, "shall state whether the amount of the deferred balance will appear on each bill the customer receives and that the customer may call the REP at any time to determine the amount that must be paid to satisfy the terms of the deferred payment plan." Under the earlier draft, the requirement that the customer may call the REP at any time to receive their outstanding balance only applied if the balance was not provided on the bill.

The updated draft changes the schedule for reconciling levelized payment plans to at least every 12 months, instead of at least every six months. REPs may still recalculate the average consumption and adjust the customer's required minimum payment as frequently as every billing period.

New language also clarifies that a REP shall not place a switch hold on accounts entering levelized payment plans if the customer is not delinquent when the plan is established, unless the plan is established as an alternative to a deferred payment plan.

As under the current rule, a REP shall not authorize disconnection of a delinquent Critical Care Residential Customer when that customer establishes that disconnection of service will cause some person at the residence to become seriously ill or more seriously ill. The prohibition shall last 63 days from the issuance of the bill. Consumer groups have requested that the Commission extend the 63-day provision to the new category of vulnerable customers, Chronic Care Residential Customers.

The draft provides that if a TDU refuses to disconnect a Critical Care Residential Customer, it shall cease charging all transmission and distribution charges and surcharges for that premises to the REP. TDUs wish to continue billing securitization charges to the REP under this provision.

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The Retail Markets Working Group report used the PPL rate ready collaborative report as a starting point, soliciting comments from additional distribution companies, suppliers and other stakeholders regarding the PPL findings (Matters, 4/22/10).

To begin, the Retail Markets Working Group reached a consensus that the rate code driven model of rate ready billing is appropriate, though some suppliers agreed with this recommendation as a first priority while reserving the right the continue to seek price driven rate ready billing. Distribution companies cited significant IT obstacles present in implementing a price driven model.

However, ConEdison Solutions noted that some distribution companies currently require up to 90 days to program a new rate code - a timeframe that is unworkable from ConEdison Solutions' perspective.

The working group did not reach consensus on a uniform method for creating new rates. The group noted that uniformity may not be necessary if the distribution companies adhere to stipulations concerning timely addition of new rates from suppliers.

PPL reported that it will be implementing a website for suppliers to manage their rates to make it functionally easier for suppliers to manage the rate ready program in a timely manner. Duquesne currently uses a manual process to create new supplier rates, which today is typically handled through emails. Duquesne reported that its experience has been that the turnaround time is five business days or less, with no more than 100 rates at a time.

The FirstEnergy companies reported that the implementation of new rates within seven days is not feasible due to its current information and billing system. Currently, if there are 15 or less new rates, the FirstEnergy companies require approximately 30 days to implement them; and if there are 15 or more new rates, about 90 days is required.

The Retail Markets Working Group recommended as a consensus that distribution companies should process rate code changes within 14 days. However, the number of rate code changes per day may be limited, depending on the utility's IT capabilities, to a reasonable amount (i.e. 3,000). Lastly, the working group reached a consensus that the last change processed will be the effective rate code.

The Retail Markets Working Group was not able to reach complete consensus concerning pricing components for rate codes. However, the working group was able to establish minimum requirements to provide suppliers with the ability to mimic fixed rate price structures. The following rate components represent these minimum requirements:

- 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

The following pricing components represent areas of disagreement among members of the working group:

- Blocked rates
- Variable rates
- Time-of-use rates
- Real-time-pricing rates
- Percent off default service rates

Distribution companies, particularly Duquesne and PECO, contend that suppliers who wish to utilize these pricing components should do so either through dual billing or a bill ready platform where available. Both utilities reported that the disputed pricing components would require system changes, and Duquesne specifically said that it cannot currently support a percent off default service rate.

The Retail Markets Working Group reached a consensus regarding proration, agreeing that utilities should not be responsible for the calculation of prorated usage, demand, or fixed charges. Rather, utilities should be responsible for adjusting these supplier charges for future billing cycles given the timely submission of such revisions by a supplier.

Consensus was not reached on support for five decimal point precision as implemented in the PPL rate ready report, as Duquesne currently only supports four decimal point precision.

The working group reached a consensus that rate ready enrollment transactions and change transactions should be made using the currently existing EDI 814 transaction. The working group also reached a consensus that existing switching rules should apply, that distribution companies may reject enrollments for non-established rate codes, and that tax exemption information should be provided by suppliers on 814 transactions for utility calculation of supplier sales tax charges.

Working group participants pointed out that there is currently no uniform procedure for designating the effective date of transactions to change billing options, and recommended that a statewide standard for designating the effective date of a change transaction should be addressed in further discussions.

A consensus was also reached that distribution companies using rate ready platforms should calculate the budget billing amounts for both distribution and supplier charges. The distribution company will also calculate the true-ups of the budgeted amounts throughout the year.

The Office of Consumer Advocate and some industrial customers urged that a cost benefit analysis be undertaken before implementing rate ready billing at those utilities not offering it (PECO) or modifying utilities' existing rate ready programs to conform to the working group recommendations. These same parties also requested discussion of cost allocation and recovery issues for any expenditures, but PUC Staff found that such cost allocation issues were outside the scope of the working group's directives from the Commission.

The following cost estimates for implementation of the original PPL working group recommendations for rate ready platforms were submitted:

- Duquesne: $470,000
- PECO: $3,300,000
- PPL: $1,300,000