Energy Choice Matters

November 19, 2009

Nelson Proposes Giving REPs Option of Calculating End Date for Contracts

As discussed at the most recent open meeting, PUCT Commissioner Donna Nelson has proposed giving REPs an option on how to determine the end of a fixed price contract, with different termination fee waiver periods applicable depending on the method. Nelson filed proposed language governing contract expiration notices (project 37214, Subst. R. 25.475) and common billing terms (project 37070, Subst. R. 25.479) in a memo filed in advance of Friday's open meeting.

Nelson has been meeting with stakeholders the past several weeks to address remaining items to be decided in the rulemakings (see Matters, 11/6/09).

Nelson recommended that under the first method of determining the end date, REPs would provide customers with a specific end date on the customer's bill. REPs choosing to list a specific end date must only waive any termination fee for a period of 14 days prior to contract expiration, and not the entire length of time from when the REP sends a renewal notice, as in an earlier proposal. The notice, to be sent out 30 to 60 days prior to the residential contract expiration date, would be required to clearly state there is a 14-day waiver of termination fees, and must also include a description of the termination fees that will be charged before the waiver period begins.

Under this first option, a REP would be permitted to keep charging the current contract rate until the next meter read on or after the listed end date, answering concerns that the meter read (and thus contract end date) could be delayed from what the REP lists on the bill due to the fluid nature of

Continued P. 6

Peevey Sets Schedule to Address Expansion of Calif. Direct Access Under SB 695

California PUC President Michael Peevey began the PUC's process of addressing the expansion of eligible direct access load under SB 695 by setting the matter for review in Rulemaking 07-05-025, and establishing a procedural schedule that will allow the Commission to adopt and implement a schedule for reopening direct access by the statutory deadline of April 11, 2010.

In an assigned commissioner's ruling, Peevey directed that a sub-phase of R. 07-05-025 be instituted to address only to those issues that must be decided within the initial six-month time limit mandated by SB 695.

SB 695 expands the amount of non-residential load eligible for direct access up to a cap set as the maximum total kilowatt-hours supplied by all other electric providers to distribution customers of a specific electric utility during any sequential 12-month period between April 1, 1998, and October 11, 2009 (the law's effective date). The new eligible load is to be phased in over a period of three to five years (Matters, 10/13/09).

As the starting point for implementing the new cap, the applicable amount of the increase in maximum allowable direct access load for each of the major electric utilities must be identified, Peevey said. Accordingly, each major electric utility shall file by December 3, 2009, the relevant information identifying the applicable maximum cap in direct access load in accordance with SB 695. In addition, each utility shall indicate the number of direct access eligible customers currently on bundled service in its distribution territory, and quantify the associated loads, in annual kilowatt-

Continued P. 7

Allegheny Files Md. POR Discount Rates

Allegheny Power has filed to impose a 1.42% discount rate for its Maryland electric Purchase of Receivables program for customers eligible for residential Standard Offer Service.

Receivables from customers eligible for Type I Standard Offer Service would be subject to a discount rate of 1.01%. Receivables from customers eligible for Type II Standard Offer Service would also be subject to a discount rate of 1.01%. The discount rate for receivables from customers eligible for hourly-priced large customer service would be 0.79%.

Each discount rate is comprised of: (1) program development and implementation costs, (2) administrative costs, (3) risk percentage associated with the continuation of the supplier-customer relationship; and (4) uncollectible expenses.

The discount rate is to be recalculated each year, to be effective for the 12-month period beginning each January, pending Commission approval. The discount rate will consist of estimated costs for the upcoming January through December, and a Reconciliation Adjustment to correct for over/under-collection of actual and estimated data from the prior period ending each December.

The Reconciliation Adjustment would be calculated on the over/under-collection separately by Service Type. Over/under-collections would be recorded in a regulatory asset or regulatory liability, representing the difference between cumulative costs eligible for recovery and discount amounts for purchased receivables.

Allegheny sought approval of its compliance plan to be effective December 15, 2009. To reduce potential customer and supplier confusion regarding bill payment during the transition, Allegheny said that it will purchase the current billed accounts receivables balance on each consolidated bill.

Under POR, suppliers will receive an EDI 820 transaction for the current balance according to the established 820/ACH payment process. Effective with 810 charges received on or after December 15, 2009, Allegheny will purchase the current balance with each bill. Suppliers will receive the EDI 820 and the accompanying ACH payment approximately 21 to 25 days after the bill is issued.

Cancel/rebills sent after the implementation of POR will be purchased at the discount rate in effect at that time.

MXenergy Reports Narrowed Loss, Continued Attrition

MXenergy reported a loss before income tax benefit of $10.2 million for the quarter ending September 30, 2009 (first quarter of fiscal 2010), narrowing the year-ago loss before income tax benefit of $104.6 million, primarily due to the comparative impact of changes in the market price of natural gas during the respective reporting periods.

Adjusted EBITDA improved to a loss of $3.6 million for the three months ended September 30, 2009, as compared with a loss of $10.3 million for the same period in the prior fiscal year. During the three months ended September 30, 2009, higher natural gas and electricity gross profit were partially offset by incremental, non-recurring general and administrative expenses incurred in connection with MXenergy's previously reported restructuring, which included an exchange offer of certain debt, and a new supply and credit agreement with RBS Sempra.

Gross profit excluding unrealized impacts from risk management activities was higher at $13.3 million, versus $4.7 million a year ago. Most of the gain was in natural gas gross profit, which improved to $7.7 million from $545,000 a year ago on an $11.8 million improvement in MXenergy's weighted average cost of gas versus the year-ago quarter. This gain was partially offset by realized hedging losses and lower volume, the latter of which had a $700,000 negative impact on gross profit versus the year-ago period.

Electricity gross profit improved to $5.5 million, up from $4.1 million a year ago, due to the favorable pricing environment in certain markets, which significantly increased gross profit per MWh sold. Higher gross profit per MWh sold was partially offset by a 15% decrease in electric volumes, which primarily resulted from lower average electricity

MXenergy Sales Data

Three Months Ended September 30,

	2009	2008
Natural gas:		
RCEs at end of period	470,000	576,000
MMBtus sold during the period	4,345,000	5,128,000
Sales per MMBtu sold during the period	$11.85	$15.63
Gross profit per MMBtu sold during the period	$1.77	$0.11
Electricity:		
RCEs at period end	77,000	99,000
MWhrs sold during the period	216,000	258,000
Sales per MWhr sold during the period	$113.32	$164.36
Gross profit per MWhr sold during the period	$25.68	$15.94

Residential Customers Equivalents (RCEs) served.

Gross profit per MMBtu sold during the quarter increased to $1.77 versus $0.11 a year ago. Gross profit per MWh sold during the quarter increased to $25.68 from $15.94 a year ago (see chart for aggregate and per unit sales data).

As of September 30, 2009, total RCEs were 547,000, down from 562,000 as of June 30, 2009, and 675,000 a year ago. Natural gas RCEs fell to 470,000 from 487,000 as of June 30. However, electric RCEs improved to 77,000 versus 75,000 as of June 30.

MXenergy's lower customer count reflects the previously reported reduction in marketing efforts to conserve capital, tighter credit screening, and higher attrition due to restrictions on pricing under its old credit agreement prior to the restructuring. As a result of the restructuring, MXenergy said it now has the ability to market a wider variety of products to current and potential customers using its traditional marketing channels.

Advertising and marketing expenses for the quarter ending September 30, 2009 were down at $353,000, from $821,000 a year ago. General and administrative expenses were higher at $14.5 million, from $12.6 million a year ago, on non-recurring charges related to the restructuring

While customer renewals for the 12 months ended September 30, 2009 improved to 90% from 84% a year ago, in-contract attrition was sharply higher at 33% versus 19% a year ago. Higher attrition reflected credit-related attrition that was higher than historic levels due to difficult economic conditions, particularly in the Georgia natural gas and Texas electricity markets, as well as the Ohio, Michigan and Indiana natural gas markets. Credit-related attrition was particularly high in Georgia, partially due to expected credit quality issues within the portfolio of customers acquired from Catalyst Natural Gas in October 2008. Additionally, in an environment of falling prices, MXenergy was unable to offer customers who had locked in a fixed rated when prices were higher a lower alternative rate (blend/extend, etc.), due to restrictions in its former credit agreement.

MXenergy's provision for doubtful accounts for the quarter ending September 30, 2009 increased to $1.6 million from $1.3 million a year ago, despite a reduction in total revenues in markets where customer accounts receivable are not guaranteed by LDCs. The higher provision primarily relates to continued deterioration of the aging of billed customer accounts receivable within natural gas markets in Georgia and the northeastern U.S. Higher provision for doubtful accounts in Georgia and the northeastern U.S. was partially offset by lower provision in the Texas electric market, which was due to lower revenues and more stringent credit standards for customers in that market.

MXenergy's provision for doubtful accounts as a percent of sales in non-guaranteed markets increased to 3.26%, versus 1.71% a year ago. During the three months ended September 30, 2009, approximately 64% MXenergy's total sales were within markets where LDCs do not guarantee customer accounts receivable, while 36% of total sales were within markets where LDCs guarantee customer accounts receivable at a weighted average discount rate of approximately 1%.

Cleveland Electric Illuminating Seeks to Offer Peak Time Rebate Pilot

Cleveland Electric Illuminating, Ohio Edison and Toledo Edison filed at the Public Utilities Commission of Ohio for approval of a smart grid pilot that would include the installation of up to 44,000 advanced meters at CEI, and the option of a peak-time rebate product for a limited number of CEI customers.

The FirstEnergy utilities proposed an initial deployment of 5,000 advanced meters, with the potential for the deployment of another 39,000 meters based on the initial pilot results. All deployments would occur in an area near Cleveland within CEI's territory.

In conjunction with the smart meter deployment, CEI would select an initial 4,000 customers and then another 39,000 customers for a peak-time rebate pilot under Rider PTR. The initial group of 4,000 customers would be assigned by June 2010, with the additional customers assigned by June 2012. The rider would be in effect through August 31, 2012.

The only eligibility criteria listed in Rider PTR included in the FirstEnergy utilities' application is that the customer cannot be taking service under a critical peak pricing rate schedule, and must be within the geographic confines of the smart grid pilot. No mention is made of any restrictions related to whether the customer is taking supply under the Standard Service Offer, nor do the FirstEnergy companies describe the selection process.

The peak time rebate would provide rebates of either 80¢/kWh or 40¢/kWh for reductions during 15 peak events called by CEI during the summer. When placed into the program, customers will be randomly assigned into a pilot paying either 80¢/kWh or 40¢/kWh of reduction. Customers will not be penalized for not reducing usage or increasing usage during peak events. Rebates would appear as a line item on bills.

Revenue shortfalls created by the peak time rebates would be recovered from all CEI customers on a nonbypassable basis, with the exception of customers taking service under Rider GT (General Service - Transmission), who would not pay for any such shortfalls.

The smart grid pilot, which includes various distribution-related elements as well, would cost $72.2 million, half of which is to be covered by a Department of Energy grant.

National Grid Says PSC Cannot Grant Plymouth Rock's Requested Relief

Brooklyn Union Gas (National Grid) petitioned the New York PSC to deny Plymouth Rock Energy's request for dispute resolution under the Uniform Business Practices related to Grid's refusal to permit the conversion of certain Service Classification No. 6 - Temperature Controlled (TC) customers to firm service under Service Classification No. 3 (09-G-0814).

As only reported in *Matters*, Plymouth Rock is seeking reimbursement for supply costs it undertook after Grid informed it and a customer that certain accounts would be switched to firm service. Grid later reversed its decision and denied the transfer of the accounts to firm service, making the supply arranged for by Plymouth Rock unnecessary (Only in Matters, 11/16/09).

"Whatever the merits of Plymouth's claim, it is beyond the scope of the Commission's authority," Grid said, noting that Plymouth Rock is essentially asking for a Commission order requiring the payment of damages.

"The Commission has authority under Section 118(3) of the Public Service Law to require a utility to provide a refund or credit to a customer when a payment has been made in excess of the correct charge for actual service rendered. It has no authority to order damages. Plymouth is not seeking a refund or credit for a utility overcharge, it is seeking damages. This claim must be dismissed," National Grid said.

Integrys Marketer Seeks FERC Assurance that SECA Settlement Won't Impact its Claims

Calling the still pending Seams Elimination Cost Adjustment (SECA) proceeding at FERC a "travesty to retail suppliers," Integrys Energy Services sought assurances from FERC that a recent SECA settlement among various Exelon and FirstEnergy companies will not preclude recovery of any SECA amounts which may ultimately be found due to Integrys Energy Services (and its affiliate Quest Energy) based on a subsequent Commission or Court order.

Integrys Energy Services noted that the Exelon-FirstEnergy settlement contains a provision holding that, "[t]o the extent the final resolution of these SECA Proceedings results in a shift or assessment to any FirstEnergy Entity of all or a portion of the SECA obligation that was owed to Exelon by Green Mountain Energy Company or Quest Energy, L.L.C. under the compliance filings set for hearing in these SECA Proceedings, such FirstEnergy Entity shall pay seventy percent (70%) of such SECA obligation that is owed to Exelon."

Integrys Energy Services noted that it and Quest reached a settlement with Commonwealth Edison, an Exelon company, regarding SECA fees. Integrys Energy Services, "expects that any settlement reached will not preclude recovery of any amounts found owing from any Transmission Owner."

FERC's initial decision in the SECA case was issued on August 10, 2006, and the hearing record has been complete and pending Commission decision since October 10, 2006 (ER05-6-001).

Briefly:

Shipley Energy Seeks Authority to Market Gas at PECO

Shipley Energy Company applied at the Pennsylvania PUC to expand its natural gas supplier license to include the PECO Gas territory.

PUCT Opens Docket for Rulemaking on REP Changes in Ownership or Control

The PUCT opened project 37685 for a rulemaking to amend rules relating to changes in ownership or control of a REP. Commissioner Kenneth Anderson requested that the rulemaking be opened, and had previously filed a strawman on changes in REP control (see discussion in Matters, 11/6/09).

UI Reports Wholesale Suppliers

United Illuminating reported that, for the first half of 2010, the following suppliers won tranches of Standard Service load: Conectiv Energy Supply, Constellation Energy Commodities Group, Hess Corporation, Sempra Energy Trading, and Shell. For the second half of 2010, the following suppliers won tranches of UI Standard Service load: Conectiv Energy Supply, Constellation Energy Commodities Group, Hess Corporation, NextEra Energy Resources, and Sempra Energy Trading. UI also reported that Hess Corporation won 100% of UI's Last Resort Service supply for the three-month period beginning January 1, 2010.

PUCT Opens Submetering Rulemaking

The PUCT opened project 37684 for a rulemaking to amend rules relating to electric submetering and master-metered apartment buildings

National Grid Again Rejects Rhode Island Long-Term Offshore Wind PPA

Narragansett Electric (National Grid) said a revised price for electric supply from a long-term contract with Deepwater Wind's wind project off the coast of Rhode Island is still uneconomic (Docket No. 4111, Matters, 10/21/09). Grid reported that the revised price is initially 25.3¢ per kilowatt-hour, with the price escalating 3.5 percent annually. While lower than the initial proposal of 30.7¢ per kilowatt-hour, Grid told the Rhode Island PUC that other renewable projects are likely cheaper.

EDP Renewables to Invest $4 Billion in U.S. Wind Through 2012

EDP Renewables, a subsidiary of Energias de Portugal and owner of Horizon Wind, said it plans to invest approximately $4 billion in constructing new U.S. wind farms through 2012. Horizon currently has a U.S. fleet of 2,500 MW, and projects a fleet of 4,500 MW by 2012. Investments are to be focused on the West Coast and the Midwest. Horizon is not considering additional Texas investment, citing an oversupply of wind in the market.

Nationwide Energy Portal names Three Senior VPs

Nationwide Energy Portal, which offers various software solutions for retail energy sales and backoffice functions (Matters, 9/10/09), named Raymond Hoppe as Senior Vice President for Business Development. Hoppe was previously senior vice president for sales and marketing at Affordable Power, and also served in various roles at Vantage Power Services, Excelergy, Automated Power Exchange, Duke Energy Trading & Marketing, and Houston Industries (Reliant). Nationwide also named Linda LeMaster as Senior Vice President of Operations. LeMaster has served as CEO at broker Respond Energy Solutions, Director Of Finance at First Choice Power, and trading & accounting manager for TXU. Brian Smith was appointed as Senior Vice President, Wholesale at Nationwide. Smith previously worked as a senior software development designer for ERCOT shadow settlements, and also developed various forecasting software solutions for Ambit Energy, and managed forecasting at Stream Energy

PUCO Approves RPM Rider at Dayton Power & Light

The Public Utilities Commission of Ohio approved Dayton Power & Light's application to institute a PJM Reliability Pricing Model Rider to cover RPM costs, net of credits. Though the costs were approved for recovery in DP&L's electric security plan, DP&L had previously applied to include the costs in its existing transmission rider, which PUCO did not approve since the RPM costs are not transmission costs (Only in Matters, 9/10/09). The Rider is applicable only to customers taking standard offer service. A breakdown of RPM rider charges by class may be found in docket 09-256-EL-UNC, in DP&L's September 23, 2009 filing.

ConEd Electric Joint Proposal Delayed By One Week

The submission of a joint proposal in Consolidated Edison's pending electric rate case has been pushed back to November 24, 2009, to allow for further drafting of the specific language of the settlement document, two ALJs reported yesterday. The joint proposal had been expected yesterday (Only in Matters, 10/23/09). The ALJs also said that all parties are now expected to either support, or not oppose, the joint proposal.

Contract End Dates ... *from 1*

meter reading schedules.

As a second option, REPs could choose to estimate the contract end date by referencing the first meter read on or after a specific calendar date. Under this option, REPs would be required to waive all termination fees once the customer receives their termination notice, and provide notice of the waiver period in the renewal notice.

In redlined language reflecting the proposed changes, Nelson re-inserted Staff's original recommendation that the end date should to be listed on all fixed price bills, both residential and small commercial.

Nelson's proposed language maintains her earlier recommendation to allow REPs offering variable plans to pass through changes in TDU, ERCOT and similar regulatory charges in the first month of billing, which is currently prohibited. However, the revised language clarifies that any pass-through may only reflect changes in TDU and similar fees that were implemented after the issuance of the Electricity Facts Label for that product.

Regarding common billing terms, Nelson's language clarifies that REPs may continue to aggregate TDU or REP charges, while requiring REPs to use a term defined by the PUCT for any line-item charge covered under the Commission's definition. REPs would be prohibited from adding a mark-up to TDU charges.

Nelson also submitted revised abbreviations for several terms meant to make them more readily understandable. REPs would be able to use other abbreviations, but only if those abbreviations are identified and spelled out on the customer's bill.

However, Nelson has recommended not allowing REPs to interchangeably use the terms "charge," "fee," "factor," and "surcharge," after concluding that use of different terms would hamper customers' comparisons of bills from different REPs. Nelson's draft would still allow flexibility for adding a suffix, changing capitalization, and adding the word "total" to a defined term.

Furthermore, Nelson's proposal removes "monthly charge" as a defined term, which had been defined as any charge assessed on a monthly basis without regard to the customer's demand or energy consumption (excluding TDU fees, taxes, etc.). In its place, Nelson proposed defining "Base Charge or Customer Charge" as a charge assessed during each billing cycle without regard to the customer's demand or energy consumption.

Regarding an implementation date for the new requirements, Nelson did not make a recommendation, noting February 1, 2010, March 1, 2010, and June 1, 2010 have all been discussed.

Calif. ... *from 1*

hours, for customers whose three-year commitment period to bundled service expires over the next three years.

The scope of the sub-phase is to be limited only to those issues that must be decided by April 2010. The preliminary list of issues to be addressed in the sub-phase are:

1. Determining the Direct Access Cap and Baseline Amounts Subject to SB 695.

2. Establishing the Phase-in Schedule:

a. What should be the length of the phase-in period, within the three-to-five year range permitted under SB 695?

b. What percentage of the total load cap should be allocated to each year of the phase-in period?

3. Monitoring and administration issues to be addressed include:

a. Should unused cap in one year roll into the next year?

b. Should monitoring continue beyond the initial phase-in to keep up with direct access load changes?

c. Should direct access eligible-load receive preference in returning for the intermediate years as long as the overall cap is not exceeded?

d. Should a set-aside be applied for direct access eligible customers if load is approaching the overall maximum during the phase-in years?

e. How frequently should utilities post updates, so that parties know where direct access load is in relation to the cap?

f. What allocation process should be used when more Direct Access Service Requests are submitted than can be accommodated under the cap, consistent with orderly enrollments, clarity, transparency, and up-to-date data?

g. What applicable non-bypassable charges are involved?

4. Process for Utility Customer Notification of new Direct Access Provisions.

5. Effects on Direct Access Switching Rules (see D.03-05-034; D.03-06-035):

a. Should the three-year minimum stay requirement be waived for customers currently in their three-year minimum stay? Could they otherwise be precluded from going to direct access due to the cap? Is the minimum stay requirement necessary in a capped market where the utilities will have more certainty as to the amount of direct access load?

b. Six-month notice requirements were developed to govern the switching of customers who were returning to bundled service or returning to direct access after serving out their three-year minimum stay. Should the notice rules be waived for bundled customers who are direct access eligible and subject to the six-month notice since the utilities will have knowledge as to maximum direct access load to guide their procurement planning under SB 695 rules?

Under Peevey's schedule, initial substantive comments will be due December 29, followed by a workshop on January 13, 2010. A final decision is to be on the Commission's agenda in mid-March 2010.

Once the Commission adopts the new limits on direct access transactions, Peevey said that the utilities will be required to promptly notify customers by bill insert of their options under the new rules. Commission Staff will confer with each utility to develop the appropriate language to include in a bill insert.

To the extent there are additional SB 695 implementation issues that can be decided after April 11, 2010, those issues will be deferred to a subsequent phase of the proceeding. Such issues will likely include SB 695's provision that competitive providers are subject to the same resource adequacy, RPS and carbon requirements as investor owned utilities, and issues related to generation built or procured by utilities for reliability purposes.

In light of the priorities of SB 695, and its prohibition on reinstating full direct access absent legislative approval, Peevey ordered the suspension of monthly reports regarding the status of Department of Water Resource contract novations. Utilities shall still pursue cost-effective novations, however.