Energy Choice Matters
November 2, 2009

Texas Termination Fees Would be Prohibited After Contract Expiration Notice Sent

Texas REPs would not be allowed to charge a customer a termination fee once they have sent a contract expiration notice to the customer, under a proposal for adoption filed by PUCT Staff in project 37214. The docket concerns implementing the contract expiration notice provisions contained in HB 1822 (Only in Matters, 7/27/09).

The prohibition would apply to both residential and small commercial customers because, "there could be some overlap between the time a termination penalty would otherwise apply and the time the customer receives the [expiration] notice and acts on it," Staff said. Currently, the PUCT prohibits a termination fee 14 days prior to contract expiration. Several consumer groups had requested an extended period to coincide with the expiration notice dates (Only in Matters, 9/15/09).

Under the current rules, expiration notices must be sent 14-45 days ahead of the expiration date for all mass market customers. Under the proposal for adoption, residential customer notices would be required to be sent 30-60 days ahead of expiration, and small commercial notices would be required to be sent 14-60 days ahead of expiration.

In other words, the termination fee prohibition would apply for up to 60 days before the product's termination, with the length of the prohibition depending on when the REP sends the notice.

All other things being equal, then, REPs would have an incentive to send notices as late as possible to customers, to minimize their exposure to a termination fee which cannot be collected. That would likely reduce the amount of time customers have to shop to the minimum notice period,

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PPL, OCA, Suppliers File 2010 POR Settlement, All-In Requirement Removed for Small C&Is

PPL, the Office of Consumer Advocate, Office of Small Business Advocate, Retail Energy Supply Association and other competitive suppliers have reached a settlement that resolves most issues regarding PPL's Purchase of Receivables program for 2010, but leaves two issues to litigation (Only in Matters, 9/14/09).

Under the settlement, PPL would not impose an all-in/all-out requirement for participation in the POR program with respect to small commercial customers [Rates GS-1, GS-3, GH-1(R), GH-2(R), IS-1(R), BL, SA, SM(R), SHS, SE, TS(R), and SI-1(R)]. Suppliers could elect to sell the receivables of only a portion of their small commercial customers to PPL. However, all small commercial customers for whom PPL performs consolidated billing would be required to participate in the POR program. Suppliers could continue dual billing small commercial customers they wish to exclude from POR, but POR would not be available to any dual-billed customer.

The POR discount rate for small commercial customers would be 0.17%, representing an uncollectibles rate of 0.12% and an administrative component of 0.05%. PPL would be authorized to change the discount rate for an individual supplier if that supplier's uncollectibles under the program exceed 1.5%, in order to prevent gaming. A supplier selling all of its small commercial receivables to PPL would not be subject to such potential modification.

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Duke Energy Retail Sales Retains 2/3 of Load Lost by Affiliate EDC

Duke Energy Retail Sales has captured two-thirds of electric customers migrating away from affiliate Duke Energy Ohio, Duke reported in releasing third quarter earnings Friday.

Duke CFO Lynn Good reported that switching has increased to 30% of load in the Duke Ohio territory as of September 30 (from 10% as of July 31), but said that only a net 10% has left the Duke corporate family, as Duke Energy Retail Sales has experienced success in retaining affiliate customers.

Margins, though, are higher for Duke in serving customers on the distribution company's electric security plan rather than serving the same customers competitively, Good reported, although Duke Energy Retail Sales is retaining customers at a profit.

Due to the net migration and lower margins of retained customers, Duke estimated that it will see about a $25-40 million ($0.02 to $0.03 per share) negative impact for the year from switching activity at Duke Energy Ohio.

Good reported that most of the migration at Duke Energy Ohio has been from individual commercial and industrial customers, and there is not a large opt-out aggregation presence in the service area, although a few aggregations are on the November ballot.

Duke Energy Retail Sales has also been winning customers in other Ohio service areas, Good said.

Duke's Commercial Power unit reported EBIT of negative $234 million for the third quarter, versus negative $108 million a year ago. Results were driven lower by non-cash impairment charges primarily related to goodwill associated with non-regulated generation operations in the Midwest in the amount of $400 million, and mark-to-market impacts. The goodwill impairment charge reflects the current estimated value of the Midwest assets, which has declined principally as a result of sustained lower power prices and demand. Excluding these items, adjusted EBIT for Commercial Power was $182 million compared to $93 million a year ago.

Adjusted EBIT increased due to $29 million in improved results from Commercial Power's Midwest gas assets, resulting from higher PJM capacity revenues, and the non-recurrence of the year-ago Lehman Brothers reserve of $15 million. Midwest gas assets contributed $32 million of adjusted EBIT for the third quarter of 2009. Commercial Power also saw a $24 million benefit from increased margins due to electric security plan rates at Duke Energy Ohio.

Duke has not filed its 10-Q.

Constellation Seeks NEPOOL, ERCOT, MISO Generation in 2-3 Years to Back Customer Load

Constellation Energy hopes to acquire generation assets in New England, ERCOT, and the Midwest ISO to back its customer supply contracts upon the close of EDF's investment in its nuclear business, CEO Mayo Shattuck reported during an earnings call.

While Constellation has discussed for several quarters its strategy to align its generation and customer load in additional markets as it does in PJM and the New York ISO, where it has significant generation, Shattuck's comments Friday were the strongest indication yet Constellation expects to be active in the near term in pursuing additional generation, or offtake agreements.

"Our strong cash position and overall market conditions allow us confidence that we can meaningfully add to our generation fleet over the next two to three years," Shattuck said.

CFO Jonathan Thayer said that upon the close of the EDF transaction (which Constellation is pursuing with the Maryland PSC's conditions), Constellation expects to have roughly $1 billion to reinvest to support its strategy of acquiring generation supply to dedicate to customer load. Constellation would still pursue the additional generation supply even if the EDF transaction does not close, Shattuck and Thayer said, but would likely use equity to finance any acquisitions with a balance of debt appropriate to the maintain its desired investment-grade rating.

Alignment of Constellation's generation footprint and load obligations is estimated to be 60% in 2010.

Constellation's customer supply unit

continues to see "strong" retail margins on new business, benefiting from the current energy price environment and reduced competition, Shattuck said. Customer attrition among Constellation's wholesale supply portfolio has also decreased, Shattuck added.

New retail electric supply contracts originated in the third quarter had a gross margin of $7.25/MWh, reported Senior Vice President Kathleen Hyle. Retail gas gross margins are holding at around $0.22/Dth, Hyle added, as Constellation has seen a range of $0.22 to $0.25 in recent months. However, higher margins could not fully offset lower volume, and earnings from the customer supply business were down $34 million year-over-year. On an adjusted basis, gross margin for customer supply was $126 million versus $119 million a year ago.

Earnings from Constellation's competitive generation were down $6 million year-over-year due to a planned outage at the Ginna nuclear plant. Adjusted gross margin from competitive generation was $645 million, up from $622 million a year ago.

On a consolidated basis, Constellation's merchant operations reported adjusted earnings of $222 million versus $107 million a year ago. On a GAAP basis, merchant earnings were $116 million, versus a loss of $276 million a year ago, when Constellation incurred significant losses while exiting long power positions to reduce risk and bolster liquidity.

Constellation, EDF Move Forward With Approval from PSC

The Maryland PSC approved EDF's investment in Constellation's nuclear unit on Friday with several conditions. Constellation said early Monday that it has consulted with its Board regarding the conditions and has received approval to proceed with the transaction. Constellation said it is now moving to close the transaction as quickly as possible. During an earnings call prior to the publication of the PSC's order, Constellation said that the deal could be closed in about two weeks. EDF also said that it will commence the process to enable the close of the transaction.

Among the conditions imposed by the PSC is a $110.5 million distribution credit for residential customers. The credit, which works out to $100 per customer, must be paid prior to March 2010. The PSC also ordered various ring fencing and dividend restrictions, including prohibiting BGE from participating in Constellation's cash pool. Constellation must also infuse $250 million worth of cash into BGE by June 1, 2010.

In ordering the conditions, the PSC said that statute requires it to find benefit and no harm to consumers from the transaction, with the Commission defining consumers as BGE ratepayers. The Commission found any benefit from Calvert Cliffs 3 to be too contingent to include as a benefit of the transaction. Constellation's promise to provide a site, free of charge, for BGE ratebased generation was also too contingent, the PSC said.

The Commission stressed that questions regarding re-regulation, executive pay, and other issues were not before it in the EDF-Constellation application, and that addressing such policy questions would be inappropriate.

Additionally, the Commission noted that, "Many opponents of this Transaction expressed the fear, borne of the history of nuclear power in the 1960s and 1970s, that a decision by UniStar to build Calvert Cliffs 3 will expose BGE's ratepayers to the cost of building the plant and the risk of potential cost overruns. Under the current regulatory regime, however, UniStar will bear *all* of the financial risks of constructing, operating and decommissioning Calvert Cliffs 3, and the ratepayers will bear none."

TXU Sees Churn as Customers Migrate Toward Variable Products

TXU Energy saw a 2% decline in its residential customer count versus June 30, 2009, as customers migrated to lower-priced variable products during the third quarter, executives reported during an earnings call.

As of September 30, 2009, TXU had 1.876 million residential customers, versus 1.911 million as of June 30, 2009, and 1.909 million as of September 30, 2008.

TXU's small business (< 1 MW) customer count decreased to 273,000 from 276,000 a year ago, and its large business customer count decreased to 23,000 from 27,000 a year ago.

Total customer count as of September 30, 2009, was 2.172 million, down from 2.212 million a year ago.

Margins at TXU have returned to the normal range of 5-10%, or $25-35/MWh.

In an effort to differentiate itself, TXU no longer offers a "variable" product as defined by the PUCT, and TXU CEO Jim Burke said that many customers have opted for currently less expensive variable plans. In particular, Burke said that smaller players offering low variable rates are attracting more TXU customers, as opposed to TXU losing market share to any of the other large REPs.

TXU has launched an effort to educate customers about variable rates and their potential volatility. However, with variable rates remaining steady until a small uptick recently, Burke said that it will probably take another period of volatility to swing customer preference away from variable rates again.

In a marketing campaign, TXU cites the various drawbacks of variable products, including the potential for the rate to change every billing cycle, the potential for a limitless rate increase one month to the next (though some providers do cap this in their products), and the fact that the rate is left to the sole discretion of the REP. As part of its campaign, TXU notes that variable rates may change "with no advance notice," although REPs by rule are required to inform residential customers on their bills how to obtain the next month's variable rate, so it may be more precise to say that variable rates do not include *explicit* advanced notice.

TXU's Sophia Stoller told *Matters* that many customers do not read messages on their bills and may be unaware that they can track month-ahead variable pricing. Additionally, Stoller noted that even with such variable rate postings, customers are still required to constantly check to see if their rate has changed.

TXU's website includes excerpts from nine competing REPs' variable EFLs, terms of service, or other marketing materials, quoting the disclosures required by rule of the variable nature of the rate, and that the rate could change in future months at the REP's discretion. Although pricing history for variable rates will now be available for every residential product offered by a REP, TXU has not posted this information online as part of its EFL excerpts.

TXU's residential product offerings are dominated by fixed rate plans, but it does offer two indexed products. One is a conventional index product tied to NYMEX prices. The other, called "TXU Energy Texas Choice," is indexed, but with the price ultimately remaining in the discretion of TXU. The TXU Energy Texas Choice EFL for the Oncor area states that the customer's rate shall be as follows:

Price per kWh = (Monthly Oncor Advanced Meter Surcharge + (Monthly billed kWh Usage multiplied by the Energy Charge) / Monthly billed kWh Usage

At AEP Texas Central, where there is no advanced meter surcharge currently, the rate is defined as such:

Price per kWh = (Monthly billed kWh Usage multiplied by the Energy Charge) / Monthly billed kWh Usage

The energy charge is not tied to any market index and is set at the discretion of TXU. The product fits within the definition of indexed product, despite this discretion, because it varies, “according to a pre-defined pricing formula that is based on publicly available indices *or information* and is disclosed to the customer." By posting the current energy rate online (and making it available through other avenues), the energy rate falls within the letter of publicly available information, and the product includes the requisite "pricing formula" needed in an index rate, even if the formula in areas without the AMS surcharge boils down to an identity (e.g., the usage cancels out, and the formula essentially reads Price per kWh = Energy Charge).

In adopting amendments to Subst. R. §25.475, the Commission did not address the definition of an indexed product on point in the preamble, but said, "The purpose of these classifications is to assist customers by giving them a shorthand description of a plan that will facilitate comparing it to other similar plans. The commission concludes that the idea of an indexed price is one that has a logical meaning in the competitive energy market and can be readily understood by customers."

In this vein of product comparison, the classification of TXU Energy Texas Choice as an indexed product does seem to be an oddity. By retaining discretion to change the energy rate in the pricing formula (which is the only pricing component at TCC), there is little difference to the customer from being served on a variable rate, in terms of the notification requirements in §25.475 and not additional provisions adopted by TXU cited below.

Aside from the formula, Stoller distinguished TXU Energy Texas Choice from a variable product because TXU's terms of service requires it to provide a 14-day advance written notice in the event that the price increases, except in cases of a change in law or regulatory charges. Such a notice is not required by rule for an index plan, and is an added benefit offered by TXU. However, there is nothing preventing any REP offering a variable product from providing the same explicit advance notice of a price change, in which case the products would essentially be identical.

As an index product, the price of TXU Energy Texas Choice could vary from the price listed on the customer's initial EFL due to changes in TDU or similar charges, which cannot occur on a variable rate. Additionally, indexed products are not required to provide a history of pricing.

On Power to Choose, at Oncor and CenterPoint, there was only one other index product, from Reliant Energy, with Reliant's price tied to NYMEX.

Additional Quarterly Detail

TXU also reported a $19 million increase in bad debt from the year-ago period, reflecting higher delinquencies due to delays in final bills and disconnects resulting from a system conversion, customer losses, and general economic conditions.

Residential volume for the third quarter increased to 9,300 GWh from 9,100 GWh a year ago due to the absence of lost load associated with Hurricane Ike in the current-year quarter. Average volume per residential customer increased to 4,900 kWh from 4,800 kWh a year ago.

Small business volumes grew to 2,600 GWh from 2,200 GWh a year ago, reflecting a change in customer mix to more higher-volume small business customers. Large commercial volumes were relatively flat at 4,000 GWh.

Total retail revenues were down 3.5% at $1.97 billion, from lower pricing and customer churn (see chart for revenues by class). As previously reported, TXU reduced prices by as much as 15% to over 250,000 existing customers on month-to-month plans, as well as reductions in offerings for new customers.

Texas Competitive Electric Holdings, which includes TXU and Luminant, reported adjusted EBITDA of $1.1 billion, up from $1.0 billion a year ago. Contribution margin at TCEH was $81 million higher year-over-year from a $43 million improvement in margins from asset management and retail activities, the non-recurrence of $13 million in charges from Hurricane Ike, and $19 million in lower purchased power costs during plant outages.

On a GAAP basis, Energy Future Holding's competitive electric segment reported a loss of $25 million versus net income of $3.6 billion a year ago, due to a significant decrease in unrealized mark-to-market net gains related to commodity hedging activities.

On a consolidated basis, Energy Future Holdings reported a GAAP loss of $80 million for the third quarter, compared with net income of $3.6 billion for the third quarter 2008. Adjusted earnings were $10 million compared to a net loss of $21 million for the third quarter 2008.

TXU Revenue Data

Operating revenues:	**Q309**	**Q308**	**Change**
(dollars in millions)			%
Retail electricity revenues:			
Residential	$ 1,272	1,258	1.1
Small business	366	335	9.3
Large business and other customers	330	447	(26.2)
Total retail electricity revenues	1,968	2,040	(3.5)

Dominion Retail Earnings Higher on Customer Growth

Dominion Retail's Earnings Before Interest & Taxes for the third quarter improved to $20 million from $7 million a year ago, parent Dominion Resources said Friday. On an after tax basis, Dominion Retail's contribution to its parent was $10 million higher year-over-year.

The improvement reflects the acquisition of

Cirro Energy in Texas which closed late in the year-ago third quarter, as well as organic gains in other electric markets.

During an earnings call Paul Koonce, CEO at Dominion Virginia Power, said that declining commodity prices created opportunities for Dominion Retail in NEPOOL, PJM and ERCOT, which translated in "good, steady organic growth."

Dominion Retail's customer count increased year-over-year to 1.747 million from 1.617 million a year ago, and also improved from 1.725 million as of June 30, 2009.

Natural gas accounts as of September 30, 2009 were 635,000, up from 595,000 a year ago, but down from 654,000 in the second quarter of 2009.

Electric accounts as of September 30, 2009 were 452,000, up from 306,000 a year ago and 421,000 in the second quarter of 2009.

Dominion Retail's Products and Services customer count was 660,000 at of September 30, 2009, versus 716,000 a year ago, but up from 651,000 as of June 30, 2009.

Operating revenue from non-regulated electric sales increased to $234 million from $130 million a year ago. Operating revenue from non-regulated gas sales fell to $52 million from $109 million a year ago.

Dominion Retail electric volumes were 2.5 million MWh, up from 983,000 MWh a year ago. Dominion Retail gas volumes were 9,500 mmcf for the third quarter, up from 9,300 mmcf a year ago.

Dominion Generation EBIT from merchant assets was down at $371 million versus $395 million a year ago, mainly from a $20 million decrease in margins from uncontracted assets in PJM.

EBITDA from NEPOOL assets was higher at $342 million versus $324 million a year ago. EBITDA from merchant PJM assets was down at $50 million from $70 million a year ago.

In response to an analyst question regarding New England's forward capacity market, Dominion Resources CFO Mark McGettrick said that he expects there to be little capacity built in the Northeast as the capacity auction is expected to continue to clear at the floor due to the large amount of demand-side resources as well as reduced customer demand.

Generators, Utilities See Little Value in Md. PSC Invitation for Capacity Contracting Proposals

Nearly all generators and utilities expressed concern with the Maryland PSC's process to invite proposals for the construction of new capacity backed by long-term ratepayer contracts, or proposals for new utility-owned generation, in response by a motion from CPV Maryland for a long-term PPA with the utilities (Only in Matters, 9/30/09).

Numerous generators and utilities questioned the need for the PSC to invite such proposals, given the current demand-supply balance in Maryland and PJM, created by lower demand, transmission upgrades, incremental capacity additions through RPM, and the PSC's own gap RFP process which procured "insurance" in the form of demand response resources. The PJM Power Providers Group, in comments repeated by several others, said that the PSC is putting the "cart before the horse" in inviting generation proposals prior to any finding that there is a reliability need for such generation.

Additionally, P3 drew attention to the gap RFP process in Case 9149 in which the Commission ordered the procurement of demand response late last year. What if, P3 speculated, the Commission had ordered the construction or contracting of new generation in that proceeding -- how would costs then compare with the current energy market and supply/demand balance?

Aside from reliability, Mirant questioned whether any new out-of-market generation would lower prices, due to PJM monopsony rules.

Generators were nearly universal in faulting the PSC's open invitation as meaningless, with Mirant equating the process to a showing of hands of who would build generation in Maryland under the right circumstances. Absent a formal RFP with a defined product and structure, numerous generators said that the Commission's exercise is academic.

The Office of People's Counsel recommended that the PSC institute a formal RFP process, and cited Connecticut of as an example to follow. "The Connecticut utilities appear to be more active in attempting to acquire resources beneficial to customers than here in Maryland. Therefore, the Connecticut Department of Public

Utility Control ('DPUC') can be less assertive in the development of the procurement strategy," OPC noted in citing the DPUC's recent decision governing how the utilities may procure up to 20% of Standard Service supplies on long-term contracts.

NRG Energy requested that the solicitation process should be separated between renewable and non-renewable capacity, with renewable capacity further bifurcated between peaking/intermittent supplies and solid-fuel, baseload supplies.

Constellation Energy, among many stakeholders that see no need for the PSC's invitation for proposals, said that all proposals should explain the current reliability status in PJM and how their project compares to any need. Additionally, responders should compare their project's costs to the most recently established PJM Cost of New Entry and auction clearing prices for RPM, Constellation said.

While preferring the current SOS procurement process, Conectiv Energy said that it intends to submit a proposal to the PSC based on its two Maryland projects totaling 775 MW.

GenPower Holdings said that it is in the process of developing the 750 MW gas-fired North Keys Energy Center in Price George's County, Maryland, with operations planned for late 2014, which could offer supply on a long-term contract.

Southern Power also expressed interest in expanding into Maryland.

Briefly:

IDT Energy Seeks Maryland Electric License

IDT Energy filed an application for a Maryland license to supply electricity or electric generation services. IDT's application was not publicly available as of press time. As only reported in *Matters*, IDT recently applied for a gas license as well.

Vectren Source Reports Wider Seasonal Loss on Storage Costs

Vectren Source reported a wider seasonal loss of approximately $3.0 million in the third quarter of 2009, compared to a loss of $0.6 million in 2008, primarily due to higher storage costs due to an increasing number of customers. The third quarter of 2008 also included a $0.7 million gain associated with the sale of Source's Georgia customer base. Source's customer count at September 30, 2009 was approximately 186,000 customers, compared to 130,000 customers at September 30, 2008. Vectren's share of the ProLiance joint venture, which includes customer supply in addition to portfolio management, posted a loss of $1.6 million, compared to earnings of $12.4 million in 2008. The year-ago earnings were lifted by wider cash to NYMEX spreads, and Vectren called the 2009 quarter results consistent with typical performance.

NiSource Says Price for Sale of Marketer Reduced in Q3 Negotiations

NiSource said that during the third quarter of 2009, the terms of the sale of its unregulated natural gas marketing business were negotiated further within the parameters of the original letter of intent, resulting in a reduction in the purchase price and other adjustments. As a result, NiSource recorded an additional $3.6 million loss on the sale of discontinued operations, bringing the total loss to $12.4 million through September 30, 2009. As only reported in *Matters*, NiSource signed a letter of intent to sell the marketer in the second quarter (Only in Matters, 8/5/09). NiSource provided no other substantive update on the sale in its 10-Q, but said that as a result of the sale, net income of $0.3 million was classified as net income from discontinued operations for the three months ended September 30, 2009, and $1.5 million was reclassified to discontinued operations for the three months ended September 30, 2008.

Pepco to Complete Retail Supply Review by Year-End

Pepco Holdings expects to conclude its strategic review of Pepco Energy Services' retail supply business by the end of the year, executives reported during an earnings call. PHI is currently evaluating the possible restructuring, sale or wind down of the retail supply business. Full earnings were reported in Friday's issue (Only in Matters, 10/30/09)

Calpine Earnings Fall on Weak Texas Results

Calpine adjusted EBITDA fell slightly in the third quarter of 2009 to $586 million, from $594 million in the prior-year period, mainly from weaker results in Texas. Commodity Margin in Texas was down $46 million year-over-year at $187 million from weaker spark spreads and reduced steam sales, mitigating a $21 million increase in Calpine's West Commodity Margin to $393 million from higher hedge prices and higher market heat rates. Net income was $238 million for the third quarter versus $136 million a year ago, as the year-ago quarter included various write-downs and hedging impacts. Calpine CEO Jack Fusco reiterated his view, expressed in past earnings calls, that Calpine's growth will be through incremental capacity additions though upgrades or modernization to existing plants. Calpine will not pursue new build until the merchant energy markets rebound, Fusco said.

Calpine, PG&E Agree to DWR Novations

Calpine said that it has entered into several new power supply contracts with Pacific Gas and Electric to replace two existing supply contracts with the Department of Water Resources, as well as to increase the supply of renewable power delivered to PG&E from The Geysers. As part of the novation, Calpine and PG&E have agreed to upgrade the Los Esteros Critical Energy Facility, from a 180 MW simple-cycle generation facility to a 300 MW combined-cycle generation facility. Calpine and PG&E have also entered into a replacement contract whereby PG&E will purchase output from Calpine's 11 Northern California peaking units through 2017 and from the seven Bay Area units through 2021. The contracts are subject to PUC approval.

Ameren Merchant Generation Earnings Down

Ameren's merchant generation business reported core (non-GAAP) earnings of $62 million for the third quarter, down from $98 million a year ago. The decline was due to weaker power prices and higher fuel and related transportation and financing costs. GAAP earnings from merchant generation operations in the third quarter of 2009 were $37 million, down from $108 million in the third quarter of 2008, reflecting the weaker power market as well as hedging impacts.

Termination Fee ... *from 1*

mitigating some of the benefit of the revised rule, which is to expand the notice period for residential customers and given them more time to shop before their default renewal rate takes effect.

However, another change recommended by Staff would in turn mitigate this potential effect, as REPs would be required to post an exact end date on all residential and small commercial fixed price bills, thus giving customers ongoing notice of an expiration date. Staff said that the estimation of a contract's end date causes too much confusion, and said that REPs should know the scheduled end date based on the TDU meter read schedule once the customer switch is executed by the TDU.

Accordingly, Staff recommended that after the first month's bill, each bill, for both residential and small commercial customers, shall include the end date. However, Staff said that such a rule belongs in Subst. R. §25.479 exclusively and not §25.475 (which is being considered in project 37214), and will recommend the attendant changes in the current §25.479 rulemaking.

Recognizing that the TDU meter read schedule may change from the end date listed on the customer's bill, Staff said that the proposed termination fee prohibition, once a contract expiration notice is sent, will act as a grace period and ensure that the customer is not penalized for a switch that occurs on a date other than the contract end date.

Although Staff agreed that requiring the end date on small commercial bills is not required by HB 1822, Staff still recommended the requirement because customer knowledge of the contract end date is important.

Staff's draft preamble states that in a REP's contract expiration notice, "a description of the termination fees should be required to include the amount, and that the exact fees should be listed on the termination notice." Since no termination fee is permitted after customer receipt of the notice, the requirement seems moot. Notably, Staff's attached redline of §25.475 strikes the previous requirement to include a "description and amount" of termination fees with the contract expiration notice. Rather, REPs would be required to state that no termination fees apply after receipt of the notice.

Staff does not believe that any changes in the current 50 kW cutoff for the waiver of small commercial customer protections is required, declining a recommendation from the Office of Public Utility Counsel to raise the threshold.

Staff also adopted suggestions to allow REPs to send the contact expiration notice to residential customers via mail or email, if the customer has agreed to receive notices by email. The original draft rule would have required a mailed notice in all circumstances.

During the rulemaking, several REPs noted that prior rule changes requiring enrollment authorizations to include the customer's ESI-ID, and identification number for the Terms of Service and EFL, have proven burdensome, as customers do not typically have such information readily available. Staff agreed with the respect to the ESI-ID, and recommended the requirement that the ESI-ID be included in the authorization be stricken. However, Staff said that including the Terms of Service and EFL identification numbers in the authorization is, "very important to the customer and to the commission when researching whether the customer is receiving the correct rate and under what terms and conditions the customer is being served," and recommended maintaining each of those two identification numbers.

Reliant Energy, supported by several TDUs, petitioned the Commission in the rule to allow REPs to change the first-month price of a variable rate product from what is on the Electricity Facts Label to account for changes in TDU or similar charges, noting that fixed and indexed products are permitted to change the first month price from what is on the EFL for such reasons. "Since the REP is allowed to change the price of a variable price contract at any time after the first month of service for any reason (unlike fixed and indexed rate contracts), the commission believes that for the first month the customer should receive the price promised on the EFL and no other changes to that price should be allowed for any reason," Staff said.

Staff did not recommend changes, requested by some REPs, to eliminate the requirement to send the default product EFL to customers, and instead just direct the customer to where the EFL may be obtained. Staff also rejected a suggestion from the Steering Committee of Cities Served by Oncor to require REPs who send the default renewal product EFL separate form the expiration notice to state in the notice that the default renewal product may include, "substantially different -- and possibly higher -- rates."

Staff declined to recommend changes requested by REPs to conform rules governing fixed products to accommodate how the Commission allows TDU rate changes, which may take effect upon an ALJ's order rather than a set date (Only in Matters, 9/29/09). Staff said that if the REP cannot show the rate change as a line item on the customer's bill, it may, by current rule, provide notice on the bill that the amount billed includes price changes allowed by rules of the PUCT. However, REPs had said that even the broader notice provision is unworkable due to timing issues and suggested that REPs be allowed to include a notice on the bill that the price "may" include price changes allowed by rules of the PUCT.

Staff's proposal for adoption includes an effective date of February 1, 2010, with current contracts grandfathered from any new requirements.

PPL POR ... *from 1*

Suppliers would be able to challenge PPL's discount rate modification in dispute resolution, if their higher uncollectible rate can be justified by serving customers with poorer payment history or other reasonable explanation. Suppliers will be allowed to credit screen small commercial customers, require deposits, or deny service due to credit concerns.

PPL's residential POR program would retain the proposed all-in/all-out requirement for participation. Covering rates RS, RTS(R) and RTD(R), the discount rate would be set at 1.37%, reflecting a 1.32% uncollectibles rate and a 0.05% administrative component. Suppliers would be required to use PPL consolidated billing to participate in residential POR, and would not be allowed to reject residential customers due to credit concerns or require customer deposits.

Under the settlement, PPL revised the minimum stay requirement for customers billed through the POR program to coincide with the December 31, 2010 termination of the interim program (with the post-2010 program subject to separate litigation). PPL clarified that the minimum stay does not prevent suppliers from offering short-term products and using POR for such products.

Supplier customers on consolidated billing will be eligible for budget billing. PPL will continue to remit to suppliers payment based on the supplier's actual charges (less the POR discount), rather than the amount charged to the customer under the budget payment plan.

PPL will unbundle uncollectibles related to generation service under its POR program and place the amounts in new Merchant Function Charges included in the Price to Compare. The MFCs will be the same as the uncollectible rates used in the POR discount (1.32% residential, 0.12% commercial).

The settlement leaves the question of what receivables shall be included in "basic supply services" to litigation. Also reserved for litigation are provisions governing customer termination and reconnections under POR.

OCA has argued that customers should not be terminated if they pay an amount equal to what their default service charges would have been (even if the supplier's charges are higher). Alternatively, OCA suggested that suppliers only be allowed to sell receivables which they certify are lower than the default service rate.

In a joint brief, RESA and Direct Energy argued that OCA has no legal justification for either policy, calling OCA's proposal an unlawful regulation of supplier pricing. OCA had argued that since default service rates have been deemed by the PUC to be "just and reasonable," any charges in excess of those amounts are unjust and unreasonable, and should not be subject to disconnection. However, RESA and Direct noted that, contrary to OCA's arguments, the default service rate has not been shown to be "just and reasonable" but rather is the product of a competitive process approved by the PUC, with power sourced from the same wholesale market where suppliers purchase power. Additionally, even if OCA was correct that default service rates are just and reasonable, RESA and Direct noted that the Commission allows disconnection for rates that have not been deemed to be just and reasonable, citing purchased gas adjustment charges which are charged to customers before they are reconciled and found to be prudent, but can cause a customer to be disconnected if not paid.

PPL's existing POR program will continue for large commercial customers during 2010.