Energy Choice Matters

November 6, 2008

PNM Opts to Keep First Choice Power

PNM Resources has decided to retain competitive retailer First Choice Power, saying the decision is the best way to realize long-term value from the unit.

While "a number of folks" were interested in acquiring the retailer, PNM could not obtain "adequate value" for the unit given today's financial markets and the accompanying increased risks for transactions, PNM Resources CEO Jeff Sterba said. So, for the time being, PNM will hold onto First Choice, adopting stricter guidelines for marketing and operations to limit losses. However, higher bad debt from the summer has already set in, Sterba noted, and all PNM can do is manage the arrears as best as possible. First Choice Power bad debt increased $6.4 million pre-tax in the third quarter, compared with the same period in 2007.

First Choice reported negative ongoing EBITDA of $3.3 million for the quarter, compared with ongoing EBITDA of $11.8 million a year ago. Aside from the $6.4 million reduction from bad debt, the retailer saw a reduction in EBITDA of $2.1 million from lower sales volumes, and a reduction of $3.3 million from Hurricane Ike, compared with the same period last year. First Choice had also contracted to purchase power from Lehman Brothers Commodity Services, whose default negatively affected ongoing EBITDA by $3.9 million. However, First Choice expects to offset most of those losses as a result of purchasing lower-priced replacement power during the fourth quarter.

First Choice reported ongoing losses of $3.0 million for the quarter, compared with earnings of $6.8 million in the year-ago quarter. GAAP losses were $16.5 million, compared with earnings of $2.7 million a year ago. GAAP results reflect a non-cash impairment charge of $7.3 million, after tax.

Quarterly average retail margins were approximately $16/MWh, compared with approximately $18/MWh a year ago. Sterba said margins were $22/MWh when excluding the impacts of Hurricane

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PUCO Drops Proposal for Second Electric Renewal Notice to be Mailed

Competitive retailers in Ohio can continue to send their second contract renewal notices via email or by telephone under revised rules concerning Competitive Retail Electric Service (CRES) adopted by PUCO yesterday (06-653-EL-ORD).

A Staff proposal had originally suggested requiring the second renewal notice for contracts with automatic renewal clauses and termination fees of less than $25 to be sent vial mail (Matters, 7/24/08). However, PUCO declined to adopt the change, and maintained the current notification method of a written communication for the first notice, and choice of mailing, bill message, email or telephone call for the second notice.

The second notice, however, must now come at least 35 days before renewal, and must contain the new contract price. The first notice is required at least 45 days but no more than 90 days before renewal.

Another win for competitive suppliers is that PUCO revised the Staff proposal to exempt suppliers from the requirement to maintain records according to the FERC uniform system of accounts. Only electric utilities are subject to the requirement.

PUCO declined to adopt Purchase of Receivables or a marketer referral program run by utilities in the rules, both of which were suggested in comments by suppliers, and, in the case of POR, the Ohio Consumers' Counsel as well.

Staff's revised payment order for consolidated bills, which places past due competitive supply

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PUCT Considers Socializing POLR Bad Debt

The PUCT voted to approve a proposal for publication that would reform pricing and procedures for emergency service, currently known as POLR service, and is asking stakeholders to comment on an alternate POLR mechanism that would include socialization of POLR bad debt.

Staff's proposal, first reported by *Matters* (Matters, 10/31/08), would create three classes of emergency service providers -- Voluntary Emergency Service Providers (VESPs), Mandatory Emergency Service Providers (MESPs), and Large Service Providers (LSPs). Any eligible REP could be designated a Mandatory Emergency Service Provider, but would only be drafted to serve customers in smaller transitions. For larger transitions, voluntary and large service providers (the five largest REPs in a class/TDU area by market share) would pick up the transitioned customers.

Among the tweaks made to Staff's original draft is that each Voluntary Emergency Service Provider and Mandatory Emergency Service Provider would charge its emergency service customers its "market-based" monthly rate, as opposed to its “lowest” monthly rate as Staff had proposed.

For customers transitioned to Large Service Providers, the POLR rate would be 120% of MCPE under the revised proposal, rather than MCPE plus line losses and ancillaries as suggested in Staff's draft.

Smitherman asked for comments on a proposal that would give customers a 30 or 45 day reprieve from being charged the 120% MCPE rate upon their initial transfer to emergency service. The Commission would post a rate for all emergency service providers on a monthly basis that would only be for mass transition customers.

Under Smitherman's proposal for comment, the emergency service provider would be reimbursed for any bad debt incurred for emergency service during the initial time period, as well as for the difference between the emergency service rate set pursuant to the existing emergency service rule and the temporary lower rate charged to the mass transition customers during the specified initial period. Smitherman pointed to the "staggering" bad debt POLRs experienced this summer and their obligation to serve in discussing cost socialization.

During the same 30 or 45 day period, the customer would not be required to pay a deposit to the emergency service provider. At the end of the limited period of time, the regular emergency service rate would go into effect.

Commissioner Kenneth Anderson also suggested waiving out-of-cycle meter read costs for any emergency service customers, with such costs recovered by the TDUs via a regulatory asset.

FERC Trial Staff Recommends Another Stakeholder Process on PJM TPS Test

While there are "concerns" about the Three Pivotal Supplier (TPS) test in PJM, FERC Trial Staff concluded that, to this point, the TPS test has not been shown to be unjust and unreasonable, and recommended its retention (EL08-47, Matters, 9/8/08). However, Staff also sees the need for another stakeholder group to develop more data and understanding of the TPS test.

Market participants claiming that the TPS test over-mitigates, "provide only anecdotal evidence and provide insufficient probative data to support their claims," Staff found. No party has recommended in detail the implementation of a specific test that could readily and adequately substitute for the TPS test, Staff added.

Still, Staff has concerns about implementation of the TPS test, concluding that some of the parties claiming the test is unjust and unreasonable may not have access to the operational data to support their claims. Staff believes that such additional operational data should be made available.

Even after a series of PJM stakeholder meetings, many of the parties do not fully understand how the TPS test is being implemented, Staff found. Due to the uncertainty surrounding the implementation of the current TPS test, Staff reasoned that it is difficult to determine how, and how well, the TPS test is operating in PJM.

Staff thus suggested a facilitated stakeholder process to develop appropriate test scenarios and data designed to provide objective information regarding how the TPS test is implemented. PJM should also develop a protocol to evaluate the results of the TPS test as implemented. PJM could run test scenarios using both the current TPS test protocol and the Look Ahead Unit Dispatch System protocol, Staff suggested.

Most other reply comments filed yesterday recited previous arguments (Matters, 10/7/08). Nevertheless, comments from the Pennsylvania PUC proved noteworthy.

In describing attempts to replace or remove the TPS test, the PUC claimed that, "The generation sellers' proposed gutting of PJM's energy market mitigation tariffs strikes directly at the heart and credibility of PJM's competitive markets."

"The PaPUC urges your Commission to recognize the complaints of the generation sellers for what they are, an effort to reduce the competitiveness of PJM's markets and free generation sellers from the rigors of real competition."

"Public confidence in markets has been badly shaken by a variety of well known economic shocks and dysfunctions of the recent past. The continuation of public support for market based economic solutions is not a given," the PUC cautioned. "The danger of a capsize of public support for wholesale markets is real," the PUC concluded.

Results Lower at Duke Commercial Power

Duke Energy's Commercial Power unit reported a third-quarter EBIT loss from continuing operations of $108 million, compared to $163 million positive EBIT a year ago, due to bad debt from Lehman Brothers, hedging losses and Ohio fuel cost recovery charges.

Adjusted EBIT for Commercial Power continuing operations was $93 million, compared to $159 million in the third quarter of 2007. Commercial Power recorded a $69 million hit from the timing of fuel and purchased power costs in Ohio, with $26 million related to under-collections in 2008 that are expected to be collected by the end of this year. The remainder represents over-collections that occurred during 2007, which have subsequently been refunded.

Commercial Power's Midwest gas assets contributed $18 million less than in the prior year, primarily due to $15 million in bad debt reserves recorded on power sales to Lehman Brothers when Lehman was unable to pay for power that Duke delivered. Commercial Power does not have any other exposure to Lehman.

Net income for parent Duke Energy fell to $215 million from $607 million a year ago. Duke disclosed that the cost of its planned ratebased nuclear generation station in South Carolina has grown to $11 billion, nearly double the original pricetag.

FERC Denies Clarification of Transmission for Duquesne Zone Generation

FERC denied requests from a trio of generators (Constellation Energy, Mirant and PPL) for clarification of the exact procedures that must be applied for each transmission service request from Duquesne zone generators seeking transmission to participate as external resources in RPM after Duquesne's exit from PJM (ER08-194-003).

FERC had previously found that PJM may enter into point-to-point transmission service arrangements with the Duquesne zone generators, allowing them to satisfy RPM deliverability requirements (Matters, 4/21/08). Constellation, et. al. objected to the finding, arguing that PJM's OATT requires point-to-point transmission service requests to be placed in PJM's study queue, and to be subject to an available transfer capability (ATC) analysis (Matters, 5/3/08).

FERC, however, found that establishing generic procedures for such transmission service requests is not appropriate, because each such request for service must be judged individually under the PJM OATT. The appropriate procedure is to analyze the specific service agreements into which PJM has entered or will enter prior to Duquesne's withdrawal, the Commission said.

FERC disagreed with Constellation, et al.'s position that PJM would be violating its OATT if it fails to conduct an individualized study of every such project submitted, since Section 17.5 of the PJM OATT provides that PJM has the discretion to decide whether a study is needed in a given case to grant firm point-to-point transmission service. Similarly, section 19.1 of the PJM OATT does not require that a study of transfer capacity be performed, FERC held.

Briefly:

ERCOT to Seek Interim Nodal Funding

ERCOT intends to seek interim funding for the nodal project due to its delay, as funding mechanisms past its original Jan. 1 start date were geared towards operations rather than implementation. With only about $20 million left, ERCOT said it would effectively exhaust its spending authority by the end of November. ERCOT's board is to consider making an application for interim funding to the PUCT at its Nov. 17 board meeting.

FPL Energy Won CL&P SOLR Load

Connecticut Light and Power reported that FPL Energy Power Marketing won 100% of its Last Resort Service load for the first quarter of 2009, as procured in an October 28 solicitation.

DPUC Accepts UI Procurement

The Connecticut DPUC approved United Illuminating's Nov. 4 procurement for 100% of Last Resort Service load for the first quarter of 2009 and portions of Standard Service load for the years 2009-2011. UI was seeking 10% of Standard Service load for the first half of 2009; 20% of Standard Service load for the second half of 2009; 20% of Standard Service load for 2010; and 10% of Standard Service load for 2011. Retail prices are to be posted by Nov. 15.

Midwest TDUs Seek to Extend RSG Refund Period Forward

The Midwest TDUs submitted a second complaint regarding Midwest ISO Revenue Sufficiency Guarantee charges, for the purposes of extending the refund period beyond the current November 10, 2008 end date. The TDUs noted it appears "unlikely" that FERC will issue a ruling before the current refund period expires (Matters, 10/14/08).

SPP, ERCOT Delay Submission of Final Entergy Reports

SPP, ERCOT and Entergy Texas have pushed back to December 5 the date for submitting updated and final reports concerning Entergy's use of each RTO as a potential qualifying power region necessary for its transition to competition. Originally, the analyses were expected in the middle of November, but additional work is needed.

PUCT OKs BP RRS/QSE Settlement

The PUCT approved a $132,567 settlement with BP Energy relating to Responsive Reserve and QSE reporting violations (Matters, 10/10/08). BP failed to provide its Responsive Reserve Service obligation on March 22-23, 2007, due to a forced outage at one of the units for which it was scheduling, and failed to properly communicate the outage to ERCOT.

First Choice ... from 1

Ike and the Lehman bankruptcy, and expects to see margins exceed $22 for the fourth quarter.

Customer count fell nearly 10% year-over-year from 258,600 to 233,800. Part of the loss is from a change in strategy, Sterba said.

First Choice is de-emphasizing "passive enrollment," or serving customers it has not solicited. Many of these customers have been residents of "at risk" apartments with marginal credit, or credit just above First Choice's threshold. Typically these customers relocate quickly, Sterba said. Even with its credit metrics, First Choice has found raw FICO scores to be inadequate to protect against bad debt for this class of customers. Meanwhile, FICO scores have also not been predictive of positive customer payment trends, such as in the Hispanic market, where customers tend to have lower scores but better payment behavior, Sterba added. The results have prompted First Choice to develop more focused credit metrics instead of reliance on FICO.

First Choice is also moving away from the residential market in general because, according to Sterba, the PUCT last spring made retention of customers more difficult.

As Sterba described on yesterday's earnings call, "one of the things that the Commission did, and this happened last spring, they prohibited REPs from taking customers who were on a term product and rolling them over to a term product if you couldn't reach them."

Ostensibly Sterba is referring to the Substantive Rules' prohibition of automatic renewals for any period longer than 31 days; however, that renewal provision has been a longstanding part of the Substantive Rules. The Commission did step up enforcement of the renewal provision starting last year with a $5 million settlement with TXU Energy, and entered into a $500,000 settlement with First Choice in August (Matters, 8/4/08).

Sterba believes that the prohibition on longer automatic renewals is not a good outcome, as it places customers on what Sterba called higher-priced and more volatile month-to-month rates. Sterba noted the success rate in contacting a current customer and getting them to renew for a term product is only 20-25%.

Despite the shift in customer focus, Sterba said First Choice saw a net increase in customer count last month and expects 2% growth in the fourth quarter.

A delay in implementing price increases on fixed price term customer renewals, coupled with contractual limitations on monthly price increases for floating rate customers, prevented First Choice from recouping the dramatic increase in purchase power costs in the second quarter. First Choice's customer renewal process has since been automated, and contractual limitations on monthly price increases have been significantly changed to reduce First Choice's exposure to future price volatility.

First Choice operating revenues
by customer class
(Dollars in millions)

	3Q08	3Q07	Change
Residential	$ 144.9	$ 124.1	$ 20.8
Mass-market	16.7	16.2	0.5
Mid-market	42.7	40.5	2.2
Trading gains (losses)	0.1	(5.7)	5.8
Other	10.6	2.6	8.0
	$ 215.0	$ 177.7	$ 37.3
Actual customers (thousands)	233.8	258.6	(24.8)

First Choice GWh electric sales
by customer class:

	3Q08	3Q07	Change
Residential	772.9	886.5	(113.6)
Mass-market	73.1	101.3	(28.2)
Mid-market	340.8	348.9	(8.1)
Other	2.7	11.3	(8.6)
	1,189.5	1,348.0	(158.5)

Sterba also expressed hope the Commission would create a mechanism that prevents customers from switching REPs without fulfilling some obligation to pay their current REP. Sterba expects that the move to nodal is going to slow down with two new PUCT Commissioners, and that the current delay will be, "longer rather than shorter."

First Choice disclosed that it filed a request for alternative dispute resolution with ERCOT alleging that ERCOT incorrectly applied its protocols with respect to congestion management during the first quarter of 2008. First Choice requested that ERCOT resolve the dispute by restating certain elements of its first quarter 2008 congestion management data and by refunding to First Choice allegedly overstated congestion management charges. The amount at issue in First Choice's claim can only be determined by running ERCOT market models with corrected inputs, but First Choice believes that the amount is "significant."

At wholesale joint venture EnergyCo, PNM's share of ongoing EBITDA was $5.4 million, up from $1.7 million a year ago. EnergyCo EBITDA was negatively impacted by $0.6 million from having to resell power that had been under contract to Lehman Brothers Commodity Services. PNM's equity in ongoing net earnings of EnergyCo was $0.2 million, compared with earnings of $6.2 million a year ago.

PNM's equity in the GAAP net losses of EnergyCo was $0.9 million, compared with earnings of $6.4 million in the prior year's quarter. GAAP losses reflected the recording of a non-cash write-off related to EnergyCo's inventory balance of emission allowances under the Clean Air Interstate Rule. EnergyCo was also hurt by reduced wholesale prices from Hurricane Ike.

PNM Resources reported consolidated GAAP losses of $5.5 million, compared with earnings of $8.4 million in the year-ago quarter.

Ohio Rules ... from 1

charges first, was accepted. The new partial payment processing order is:

1. Billed and past due competitive supply charges, or, if applicable, competitive supply payment arrangement or past due competitive supply budget billing.
2. Billed and past due electric utility distribution, standard offer generation, and transmission charges or, if applicable, electric utility payment arrangement or past due electric utility budget billing.
3. Billed and due current electric utility distribution and transmission charges or current electric utility budget billing.
4. Billed and due current competitive supply charges or current competitive supply budget billing.
5. Other past due and current non-regulated charges, other than competitive supply charges.

Similar to a recent revision to competitive gas supply rules, the updated rules permit competitive electric suppliers to terminate a customer contract without penalty due to a force majeure event, without having to give customers the reciprocal right to terminate early without penalty. Force majeure events include, but are not limited to, changes in any governing law or regulation that physically prevents or legally prohibits the supplier from performing under the terms of the contract.

The revised rules clarify that competitive providers may offer net metering contracts to customers, but are not compelled to develop such products. Customers can now request 24 months of usage history from the utility, rather than the current 12.

The new rules implement several provisions of SB 221 relating to governmental aggregation, including expanding the maximum length of aggregation from two to three years.

The rules permit, as statutorily provided, governmental aggregators to waive standby fees for their customers, provided any customers returning to the Standard Service Offer will do so at the market rate. Governmental aggregation customers shall only be charged a portion (proportionate to the benefit customers receive) of any nonbypassable surcharge enacted to recover costs of any phase-in of standard service rates.

Utilities must provide governmental aggregators (or their chosen supplier) with customer lists, including account numbers, names and other pertinent information, free of charge, and must identify customers ineligible for aggregation and those currently under contract to a competitive supplier. Governmental aggregators, and not utilities, remain responsible for scrubbing customer lists for ineligible customers, PUCO held.

While NOPEC argued for the provision of load data for both customers individually and for the aggregation's load as a whole, PUCO declined to adopt the suggestion, as that information is not provided to competitive suppliers, and some utilities lack that data.

A switching fee shall not be assessed to customer accounts that switch to or from a governmental aggregation.

Marketing rules for competitive service were updated to provide that promotional materials or solicitations that, "[f]ail to conspicuously disclose an affiliate relationship with an existing Ohio electric utility," or that, "[l]ead the customer to believe that the CRES provider is soliciting on behalf of or is an agent of an Ohio electric utility when no such relationship exists," are prohibited.

The amended rules change the timeline for renewal of competitive providers' certificates. Instead of applying for renewal between 30-120 days before certificate expiration, the filing would be required between 30-60 days before expiration. If the provider files such renewal application less than 30 days prior to the expiration date, the provider shall file a motion to extend the expiration date on its current certificate for an additional 30 days. Such a motion shall be deemed automatically approved, unless otherwise ruled upon by the Commission or an attorney examiner within three business days of the filing of the motion.

The rules amend the environmental disclosure requirements applicable to competitive providers to provide that:

"Each CRES provider shall submit to staff for its review and approval a proposal for incorporating the use of renewable energy credits (RECs) within its annual and quarterly environmental disclosures. At a minimum, such submittal would be required for the following:

(a) A CRES provider sells RECs from one of its electric generating facilities.

(b) A CRES provider purchases RECs as a means of complying, in part or whole, with a renewable energy resource benchmark under the state's alternative energy portfolio standard requirements."

The final rules decline Staff's proposal to consolidate the requirements for disconnection, reconnection, establishment of service, and bill payment of all residential utility services in Chapters 4901:1-17 and 4901:1-18 O.A.C., because those chapters are currently under review in another proceeding. PUCO also rejected a proposal from consumer advocates that would require utilities to offer customers the option of adjusting their billing due dates to meet their needs, up to 21 days, since consumer advocates did not provide any supporting evidence as to why consumers require such an option, or whether it would produce the intended result. The question is also being addressed in the review of Chapters 4901:1-17 and 4901:1-18 O.A.C.

The Commission also refused to adopt a prohibition on the use of check cashing stores as bill payment agents in the instant case, since that issue is also being considered in another proceeding (Matters, 6/26/08).

PUCO agreed in principle that generation rate components should be included in the credit for excess generation under net metering, but held that generation components should be subject to two requirements -- they must be based on kilowatt-hour usage and they must be bypassable.

Furthermore, adjusting demand charges or allowing credits for reducing line losses, enhancing blackstart capability, or altering any other rate components due to net metering would constitute a change in rate structure, which is prohibited by Section 4928.67(A)(1), Revised Code, PUCO found.