Energy Choice Matters

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Bad Debt Hits $50 Million at First Choice Power

Lower average unit margins and bad debt continued to weigh First Choice Power as the REP reported negative ongoing EBITDA of $26.8 million for the year 2008, compared with 2007 ongoing EBITDA of $47.8 million. GAAP losses were $136.6 million for 2008, compared with 2007 earnings of $27.2 million.

Bad debt in 2008 grew to nearly 8% of sales at $49.2 million, up from $34 million from a year ago – an "untenable" ratio as PNM Resources CEO Jeff Sterba told investors on a conference call. Lower average unit margins impacted results negatively to the tune of $32 million, while marketing and customer service costs also increased about $10 million to $42.5 million. The increase in marketing costs was mostly due to higher call volumes and aggressive marketing campaigns designed to switch month-to-month customers to long-term contracts, which saw success.

While the effects of Hurricane Ike contributed to bad debt, Sterba thinks a bigger piece is due to market rules that allow customers to switch REPs while still owing their original REP a debt. Sterba blamed abuse of the Move-In, Move-Out transactions for customers that do not actually move for allowing customers to "hop" from REP to REP while accumulating arrears at each. The run-up in gas prices in the early part of last year exacerbated bad debt resulting from such REP hopping, Sterba added.

Sterba believes the PUCT understands that everybody in the ERCOT market is paying a high price because the rules enable people to avoid paying their bills. Changing the market rules

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U.S. Growth Fuels Energy Savings Third Quarter

Energy Savings Income Fund reported higher adjusted earnings of $46.7 million for the third fiscal quarter of 2009, up from $34.9 million a year ago, on higher gross margin, customer usage, and customer additions. All dollars amounts in this story are Canadian. On a GAAP basis, Energy Savings reported a $49 million loss due to hedging valuations, versus earnings of $28 million in the year-ago quarter.

Customer count grew to 1.775 million with 23,000 net additions from 94,000 gross additions during the quarter, compared with totals as of Sept. 30, 2008. U.S. electric customers grew to 200,000 at quarter's end, versus 177,000 as of Sept. 30. U.S. gas customers grew to 238,000 from 226,000 as of Sept. 30. Canadian electric customer count is relatively flat, while the Canadian gas customer count saw the highest attrition, falling to 756,000 from 770,000.

Annualized U.S. electricity attrition for the quarter was 19%, in line with management's target, while annualized U.S. gas attrition for the quarter was 22% -- above a 20% target but much-improved over prior quarters.

Seasonally adjusted gross margin grew 23% to $87.6 million. U.S. gas gross margin rose from $10.4 million a year ago to $25.2 million on customer additions, higher weather-related

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CIEP BGS Auction Prices Nearly Double on Credit, Capacity Costs

Driven by credit costs and Reliability Pricing Model cost increases, prices procured in the New Jersey's BGS auction for the Commercial and Industrial Energy Pricing (CIEP) customer class shot up 91% versus the 2008 auction, with a winning average bid of $205.203 per MW-Day.

The CIEP auction, which is for default service for customers above 1 MW and certain C&Is which elect hourly pricing, does not procure energy, as energy is supplied at hourly rates. Thus, the increase in the standby component from last year's winning average of $107.63/MW-Day is only expected to increase customer bills 7%, assuming similar energy prices.

The increased CIEP auction prices reflect higher credit costs reflecting both recent turmoil in credit markets and a shift from monthly to weekly account settlement by PJM, the BPU said. The hike also reflects a $45 cost increase to PJM's RPM, which accounts for 45% of the overall increase.

The winning CIEP price by territory was:

PSE&G	$203.25/MW-Day
JCP&L	$203.92/MW-Day
ACE	$215.00/MW-Day
RECO	$215.25/MW-Day

Prices in the fixed-price (FP) auction for customers under 1 MW were lower than last year's results, but will produce a slight increase in most service areas due to replacing laddered 2006 contracts with lower prices which are expiring. Prices in the FP auction ranged from 6-10% lower than the 2008 auction, as decreased fuel costs were offset by higher credit costs and risk from price volatility.

Winning FP prices were:

PSE&G	10.372¢/kWh
JCP&L	10.351¢/kWh
ACE	10.536¢/kWh
RECO	11.27¢/kWh

PSE&G customers will see the largest year-over-year increase at 0.6% of the customer bill. The increase is 0.2% at Rockland Electric and 0.1% at Jersey Central Power & Light. At Atlantic City Electric, customer rates will be flat.

A total of 17 suppliers were registered to bid in the auctions. Ten suppliers won fixed-price load: Conectiv Energy Supply, Consolidated Edison Energy, Exelon Generation Company, FPL Energy Power Marketing, Hess Corporation, J.P. Morgan Ventures Energy Corporation, Morgan Stanley Capital Group Inc., PPL EnergyPlus, PSEG Energy Resources & Trade LLC, and Sempra Energy Trading LLC.

Five suppliers won CIEP load: Consolidated Edison Energy, Dominion Retail, FPL Energy Power Marketing, Morgan Stanley Capital Group Inc., and PSEG Energy Resources & Trade LLC.

Calif. Marketers Wary of Future Cost Allocation of Utility-Owned Generation

Although a proposed California PUC decision regarding cost allocation of costs for utility-owned peaking units Southern California Edison developed in 2006 would assign costs only to bundled customers (rejecting SCE's proposal to allocate costs to both bundled and direct access customers), marketers are still concerned that the draft decision opens the door for future review of such cost allocation (A. 07-12-029)

The proposed decision says that, based on arguments from SCE and TURN, "a strong case can be made that it would have been equitable to have the costs of the peakers shared by all benefiting customers," and accordingly recommends that the scope of Phase II of the 2008 Long-Term Procurement Plans (LTPP) rulemaking (R. 08- 02-007) should be expanded to include consideration of an exception to current rules which exclude utility owned generation from the Cost Allocation Mechanism (CAM) which assigns costs to bundled and direct access customers.

The Alliance for Retail Markets and Western Power Trading Forum argued that expanding the scope of the LTPP proceeding would send a strong signal that additional mandated utility investment is likely to occur, chilling merchant development.

The proposed decision's statement signals to competitive market participants that California remains in a period of market uncertainty and confusion about whether the Commission will support its own established policies for competition, or revert to relying on utility-owned generation, AReM and WPTF said.

SCE, meanwhile, argued that the proposed decision erred by finding that the PUC is bound to an earlier ruling which allocates utility-owned generation costs only to bundled service customers, since the PUC has authority to rescind, alter or amend its prior decisions. Furthermore, SCE contended that the peakers, built at the PUC's direction, are distinct since they were not built to be "essentially dedicated" to bundled service customers, but rather for overall system reliability reasons.

IPA Backs ALJ's "Unambiguous" Definition of Broker

The Illinois Power Agency, which is mainly charged with procuring default service supplies for Illinois utilities, backed proposed ABC licensing rules contained in an ALJ's proposed order, arguing that the draft definitions would bring clarity to the licensing requirements.

The IPA favors the ALJ's proposed definition of "attempts to procure," which would require licensing for entities with an express agreement to procure electricity on behalf of a customer, and which receive compensation to act as the customer's agent. The proposed definition is an, "appropriate bright-line requirement to determine when the licensing requirements apply," the IPA said.

The state power agency opposed alternative language for the definition of "attempts to procure" offered by BlueStar Energy Services. Under BlueStar's proposal, a licensing requirement would apply to any entity that holds itself out as expert, authoritative, or experienced in the field of electric power procurement (Matters, 1/27/09).

"BlueStar's proposed modification would impose a licensing requirement on virtually any person that consults with a consumer on their alternative retail electricity supply options, whether compensated for that purpose or not," the IPA said.

Furthermore, IPA suggested BlueStar's definition would create ambiguity, as an entity's licensing requirement would be based on the verbal or written statements between a customer and the agent, and an interpretation of whether the customer perceived the statements as a representation that the agent was expert, authoritative or experienced, and whether the prospective licensee intended to make those qualitative representations. "It would be difficult, if not impossible, for the Commission to apply BlueStar's definition to each relationship created between a prospective licensee and customers to determine if a license was required," the IPA argued.

Stakeholders Cite Lingering MRTU Problems

Stakeholders cited numerous aspect of the California ISO's Market Redesign and Technology upgrade which still need to be corrected before a proposed April 1, 2009 start date, and offered, at best, conditional support for CAISO's latest planned Go-Live date.

Although stakeholders reported a host of ongoing problems with MRTU software and function, many of the issues relate to inaccurate settlements, with inaccurate dispatch instruction also a top concern.

The Northern California Power Agency reported the continued occurrence of "ghost bids" in simulations, or situations where NCPA submitted no schedule into the market, only to observe the MRTU software insert a null bid template into the process that NCPA never offered. Mirant reported that one common problem is the lack of a Reliability Must-Run dispatch notice for its units. From simulation data, it appears Mirant's RMR units are being dispatched for economics even though the prevailing Locational Market Price is considerably lower than the bid cost of the units. Because the units are not setting the LMP in the market simulation, Mirant questioned the accuracy of the CAISO's dispatch and LMP software.

The Western Power Trading Forum, along with several IPPs, urged FERC to order CAISO to freeze its MRTU software systems and, "end the continuous and impossible task of catching a moving interface target." Absent a freeze, testing market participants' systems against an ever-changing CAISO market design is impossible, IPPs added.

WPTF said it, "is not advocating that the market start be held up to resolve every last settlements-related issue," but stressed, "it must be understood that ultimately the financial outcome has to match that set forth in the FERC-approved rules," in requesting that FERC affirm that the financial outcomes of the MRTU tariff provisions as detailed by the Business Practice Manuals will govern ultimate financial outcomes.

NCPA, echoing a recommendation of several munis, argued that a safety net is required given some of the very large and still unexplained amounts still appearing in settlement statements. The current "pay first, dispute later" settlement mechanism cannot provide sufficient protection either to market participants or to the market as a whole in the event that some of the recently observed issues continue to recur, NCPA said in supporting an Interim Payment Option that would permit a buyer to make payments based on 125% of the invoice for similar service from a prior comparable period (say the same month of the previous year), and possibly somewhat more if necessary to cover the affected creditors (sellers) for their actual costs of supply.

However, WPTF opposed safety valves or other generic means of offering relief to one market participant or another, since for every dollar of relief that such a mechanism takes away, a dollar cannot be paid to those owed. The "pay and dispute" mechanism should not be discarded merely because of the implementation of MRTU, WPTF said, instead recommending that the dispute window be temporarily extended to 76 business days after the trade to give market participants an expanded opportunity to review settlements.

Briefly:

Oncor Says Young Energy in Default

Young Energy has not satisfied its debt with Oncor for charges incurred for retail delivery service, Oncor claimed in a motion to intervene in the REP application of TCS Energy (Matters, 1/23/09). Oncor noted that TCS President Brian Young was listed as Vice President of Young Energy as recently as July 2008, and noted that Young Energy's annual REP report as filed in October 2008 indicated there had been no changes to its officers. Last year Young Energy sold its book, consisting of prepaid customers, to dPi Energy, but retained its REP certificate and has remained dormant in the market.

Maine PUC Awards BHE Large C&I Load

The Maine PUC filled unserved large C&I load at Bangor Hydro-Electric by accepting a retail bid at 8.1¢/kWh for delivery starting March 1, 2009 and lasting six months. A prior solicitation did not produce final bids for the load, but the PUC received new wholesale and retail bids late last week. The winning price, 40% lower than current rates, is the lowest in three years for the class, the PUC said. Most other classes have seen price decreases in the most recent Standard Offer results as well, as PUC Chair Sharon Reishus said the PUC was pleased that, after an initial lag, "the market was able to respond to the needs of these particular customers."

Direct Pike County Price is 9.8¢

The price for the recently authorized two-year term of Direct Energy's Pike County Light and Power aggregation pool (Matters, 2/6/09) is 9.8¢/kWh, about 18% lower than last year's price.

FERC OKs NYCA ICR

FERC approved an increase in New York's installed reserve margin to 16.5% for the 2009-2010 delivery year (Matters, 12/25/08).

First Choice ... from

would help mitigate electric prices to the vast majority of customers, Sterba argued.

First Choice is continuing various measures to mitigate its bad debt, including stricter and tiered deposit requirements, and risk-based pricing based on credit profiles, including credit scores and demographics.

While PNM opted to retain First Choice after evaluating strategic options last year, Sterba said the REP's executives realize that they are being watched closely, particularly through the first three quarters of 2009. Brian Hayduk, previously of Juice Energy and Constellation NewEnergy, was brought in as First Choice CEO late last year to right the ship.

While Sterba doesn't have a specific timeline on a turnaround, he told PNM investors that, "if we can't turn this business around then we're not going to stay in it."

Sterba reported that everyone in ERCOT got hit hard this year, and as a result, REPs have moved to increase margins to make up for the losses. Pricing in the market right now is much more "rational" than was seen early last year, Sterba said, but he noted it remains to be seen how long such pricing will last, before one REP thinks it can chase something by lowering prices. Sterba said First Choice will be "disciplined" about maintaining current margins, which have rebounded from levels in the first half of the year, and now average in the mid-$20s/MWh.

First Choice has already seen a return to growth from the third quarter, where First Choice saw higher churn and also limited acquisitions due to market conditions. Residential customer count has grown to 192,000 as of January, rebounding from 182,000 during the fall, and back near summer levels of 196,000. Still, total customer count ended the year down at 237,400 versus 258,400 a year ago.

More importantly, First Choice has grown the percentage of residential customers on term, fixed price contracts to 67% from 47%.

First Choice also had its best year for commercial sales, with a 42% increase in signed margins and 31% increase in new contracts. Typical commercial contracts being signed are for three years, First Choice said.

Still, Sterba stressed that First Choice cannot be turned around on volume, and the REP's focus is on cutting costs and improving margins.

Margins are also recovering While margins sank to $11.33/MWh in the first half of 2008, margins from July through December rose to $24.21/MWh.

For the fourth quarter, First Choice reported an ongoing loss of $8.2 million and a GAAP loss of $35.6 million. The results were down from ongoing earnings of $9.9 million and GAAP earnings of $12.2 million for the fourth quarter of 2007.

First Choice recorded a $25.0 million after-tax impairment charge on intangible assets exclusive of goodwill in the fourth quarter. The charge included the lower valuation of the First Choice brand name, as Sterba believes that during a recession price is going to drive customer decisions much more than the value of a trade name.

At PNM's wholesale joint venture Optim Energy (formerly EnergyCo), PNM's share of ongoing EBITDA for 2008 was $24.5 million, compared with $4.6 million in 2007. PNM's after-tax equity in GAAP net losses of Optim Energy was $17.9 million, compared with net earnings of $4.6 million in 2007.

While Optim, which owns two online plants, will continue to evaluate expansion, executives don't see the kinds of market incentives today that would trigger a desire to

First Choice Power Operating Revenues

	Year Ended December 31,		
	2008	2007	Change
	(In millions, except customers)		
Residential	$ 407.3	$ 390.3	$ 17.0
Mass-market	52.7	61.0	(8.3)
Mid-market	149.3	141.6	7.7
Trading gains (losses)	(49.9)	(3.6)	(46.3)
Other	22.8	11.4	11.4
	$ 582.2	$ 600.7	$ (18.5)
Customers (thousands)	237.4	258.4	(21.0)

build new facilities, expect potentially in a very small niche application, where Optim can bring in a facility at exceptionally low cost.

It's not a robust market to buy assets either, executives said, as it appears many developers are trying to weather the current storm and determine how long the depressed prices will last and whether they see an opportunity to get their returns down the road. However, more developers could look to exit if current prices persist, which could make it more of a buyer's market, executives said.

Across all segments, PNM Resources reported 2008 consolidated GAAP losses of $229.7 million, compared with earnings of $74.9 million in 2007

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consumption, low supply costs, higher per-customer margins and favorable exchange rates. Average U.S. gas gross margin after all gas balancing costs for the quarter was $2.19/GJ, an increase of 49% over the year-ago figure of $1.47/GJ.

U.S. electric gross margins nearly doubled to $8.5 million from $4.5 million a year ago, on an increase in customers, favorable exchange rates and decreased commodity costs in New York. U.S. average electric gross margin during the current quarter increased by 78% to $18.13/MWh compared to $10.20/MWH a year ago.

Gross margin for customers added during the quarter is as follows:

- Canada Gas: $1.73/GJ
- Canada Electricity: $15.28/MWh
- United States Gas $2.18/GJ
- United States Electricity: $20.25/MWh

The turmoil in the credit and financial markets could create potential acquisitions of customers at very attractive prices, Energy Savings said.

Seasonally adjusted sales were $510.8 million versus $459.4 for the prior-year quarter. U.S. gas sales were $112.6 million for the quarter, up from $75.1 million a year ago. U.S. electricity sales rose to $57.9 million from $42.6 million a year ago.

Annualized gas volumes at quarter's end were flat at 105 million GJs, as Canadian attrition offset a 5% rise in U.S. annualized volumes to 25 million GJs, mostly due to strong growth in New York and Illinois. Annualized electric volumes grew 3% to 7.8 million MWh on a 13% growth in U.S. annualized volumes to 2 million MWh. Quarterly sales of Energy Savings' Green Energy Option products were 137,000 GJs of natural gas and 45,000 MWhs of electricity -- more than the amount sold in all of fiscal 2008.

Bad debt expense for the third quarter was $4.2 million versus $1.2 million a year ago, partially due to a 22% increase in quarterly revenues in the markets where Energy Savings assumes the risk for accounts receivable collections (Texas, Illinois, Alberta). Year-to-date, bad debt expense accounts for 2.3% of the revenue earned in the markets where Energy Savings bears collection risk.

General and administrative costs rose to $14.8 million for the three months ended December 31, representing a 19% increase from $12.4 million a year ago, primarily due to staffing in corporate office to support continued growth, U.S. exchange, and an increase in collection outsourcing fees. Marketing expenses, including commissions for sales reps, grew to $18.8 million from $13.9 million in the third quarter of fiscal 2008.

In the U.S., gas aggregation costs were $1.69/GJ, which is slightly above target for the year. U.S. electricity aggregation costs were $14.09/MWh, which is below the market's target of $14.25 based on higher than expected additions.

During a conference call, Energy Savings noted the flat Canadian gas market could prompt smaller marketers to exit, especially if they only have operations in Canada, which could open the door for potential acquisitions. Energy Savings also said it intends to grow its C&I business going forward (serving small to mid-merit customers), and attributed some of the higher administrative costs to that effort.