Energy Choice Matters

May 18, 2009

MXenergy Adjusted Earnings Higher, Customer Attrition Rises

Adjusted EBITDA for the quarter ending March 31, 2009 was up for MXenergy at $48.9 million, versus $31.7 million a year ago, as higher gross margin versus the year-ago period offset higher attrition. Net income was down at $9.4 million from $25.1 million a year ago, mainly from $11 million in unrealized losses from risk management activities, versus unrealized gains of $35 million in the year-ago quarter.

Gross profit was down at $57.8 million versus $86.3 million a year ago, mainly from unrealized losses. Gross profit excluding unrealized losses was up at $69.2 million versus $51.3 million a year ago.

Natural gas gross profit before unrealized losses was up at $62.6 million from $48.4 million a year ago. Gross profit per MMBtu was also up at $2.61/MMBtu versus $1.79/MMBtu a year ago.

Electricity gross profit excluding unrealized losses was higher at $6.6 million from $2.9 million a year ago, mainly on higher sales and customer count, driven by significant organic customer growth in Texas, Connecticut and New York versus the year-ago quarter. However, the gains were mostly seen in late fiscal 2008 and early fiscal 2009, and attrition has been higher the past six months. Gross profit per MWh during the quarter was up at $33.90/MWh from $19.15/MWh a year ago.

Total Residential Customer Equivalents (RCEs) as of March 31, 2009 dropped 92,000 from the year-ago period, to 594,000. Natural gas RCEs at period-end were down at 520,000 from 605,000 a year ago, while electric RCEs were down at 74,000 from 81,000. Due to the timing of customer losses (and gains in the year-ago period), the average number of electric RCEs for the entire quarter

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Calif. Draft Would Maintain Use of Best Estimate Load Forecasting for 2010 RA

California LSEs would continue to use their "best estimate" of load for forward Resource Adequacy obligations, but the requirement could change to a "current customer" approach as early as 2011, under a draft California PUC decision released Friday (R. 08-01-025).

In D.05-10-042, the PUC held that LSEs shall use their best estimate in producing year-ahead load forecasts required for Resource Adequacy compliance, instead of a forecast based on their current customer count. Some stakeholders, including Pacific Gas & Electric, have suggested adopting the current customer count approach due to their concerns about potential under-forecasting by competitive providers. Electric service providers oppose the change because of the migration which is inherent in their business, and because there is not a liquid capacity market to support trading.

The proposed decision agrees that the current lack of liquidity in the capacity market means that the best estimate forecast approach should be used for the 2010 compliance year.

"Given the importance that most parties ascribe to having the SCP [California ISO Standard Capacity Product] in place to facilitate capacity trading, we view the successful implementation of the CAISO's SCP tariff provisions as a necessary condition for adoption of the current customer approach," the draft says.

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FirstEnergy Ohio Utilities Post Retail Rates

The FirstEnergy Ohio utilities filed retail rates for the period starting June 1, 2009. Base standard service offer generation charges will remain unchanged through May 31, 2011, but some of the riders listed below may be adjusted during the interim. Listed below are the major components bypassable by competitive service customers, though certain schools and industrials may qualify for additional generation credits if remaining on standard service.

Toledo Edison

Rider GEN: Standard Service Offer Generation Charges (¢/kWh)

Class	Summer	Winter
RS		
First 500 kWh	6.8818¢	6.3047¢
All excess kWh	7.8818¢	6.3047¢
GS	7.3568¢	6.3047¢
GP	7.1014¢	6.0859¢
GSU	6.9017¢	5.9148¢
GT	6.8948¢	5.9089¢
STL	7.3568¢	6.3047¢
TRF	7.3568¢	6.3047¢
POL	7.3568¢	6.3047¢

Fuel Rider (¢/kWh)

RS	0.1058¢
GS	0.1058¢
GP	0.1022¢
GSU	0.0993¢
GT	0.0992¢
STL	0.1058¢
TRF	0.1058¢
POL	0.1058¢

Rider TAS: Transmission and Ancillary Services Rider

RS (all kWhs, per kWh)	0.1334¢
GS* (per kW of Billing Demand)	$ 0.3700
GP* (per kW of Billing Demand)	$ 0.4670
GSU (per kVa of Billing Demand)	$ 0.6470
GT (per kVa of Billing Demand)	$ 0.5180
STL (all kWhs, per kWh)	0.0533¢
TRF (all kWhs, per kWh)	0.0533¢
POL (all kWhs, per kWh)	0.0533¢

* Separately metered outdoor recreation facilities owned by non-profit governmental and educational institutions, such as athletic fields, served under Rate GS or GP, primarily for lighting purposes, will be charged per the TAS charge applicable to rate schedule POL. (applicable to Rider TAS at Ohio Edison and Cleveland Electric Illuminating as well)

Rider NDU: Non-Distribution Uncollectible Rider

All classes: 0.0586¢/kWh

Ohio Edison

Rider GEN: Standard Service Offer Generation Charges (¢/kWh)

Class	Summer	Winter
RS		
First 500 kWh	6.8818¢	6.3047¢
All excess kWh	7.8818¢	6.3047¢
GS	7.3568¢	6.3047¢
GP	7.1014¢	6.0859¢
GSU	6.9017¢	5.9148¢
GT	6.8948¢	5.9089¢
STL	7.3568¢	6.3047¢
TRF	7.3568¢	6.3047¢
POL	7.3568¢	6.3047¢

Fuel Rider (¢/kWh)

RS	(0.0668)¢
GS	(0.0668)¢
GP	(0.0645)¢
GSU	(0.0627)¢
GT	(0.0626)¢
STL	(0.0668)¢
TRF	(0.0668)¢
POL	(0.0668)¢

Rider TAS: Transmission and Ancillary Services Rider

RS (all kWhs, per kWh)	0.0243¢
GS* (per kW of Billing Demand)	$ 0.0790
GP* (per kW of Billing Demand)	$ 0.1300
GSU (per kVa of Billing Demand)	$ 0.1090
GT (per kVa of Billing Demand)	$ 0.1000
STL (all kWhs, per kWh)	0.0097¢
TRF (all kWhs, per kWh)	0.0097¢
POL (all kWhs, per kWh)	0.0097¢

Rider NDU: Non-Distribution Uncollectible Rider

All classes: 0.0566¢/kWh

Cleveland Electric Illuminating

Rider GEN: Standard Service Offer Generation Charges (¢/kWh)

Class	Summer	Winter
RS		
First 500 kWh	6.8818¢	6.3047¢
All excess kWh	7.8818¢	6.3047¢
GS	7.3568¢	6.3047¢
GP	7.1014¢	6.0859¢
GSU	6.9017¢	5.9148¢
GT	6.8948¢	5.9089¢
STL	7.3568¢	6.3047¢
TRF	7.3568¢	6.3047¢
POL	7.3568¢	6.3047¢

Fuel Rider (¢/kWh)

All classes: 0.0000¢

Rider TAS: Transmission and Ancillary Services Rider

RS (all kWhs, per kWh)	(0.0074)¢
GS* (per kW of Billing Demand)	$ (0.0220)
GP (per kW of Billing Demand)	$ (0.0240)
GSU (per kW of Billing Demand)	$ (0.0260)
GT (per kVa of Billing Demand)	$ (0.0210)
STL (all kWhs, per kWh)	(0.0033)¢
TRF (all kWhs, per kWh)	(0.0033)¢
POL (all kWhs, per kWh)	(0.0033)¢

Rider NDU: Non-Distribution Uncollectible Rider

All classes: 0.0478¢/kWh

Texas Disconnect, Standard Form Contract Bill Sent Back to House Committee

A Texas bill which would implement expanded disconnection protections, mandate a standard form retail contract, and require the development of a retail market monitor was sent back to the House State Affairs committee on a point of order late last week (Matters, 5/5/09).

Rep. Sid Miller raised a point of order against further consideration HB 3245 because the committee minutes of the April 23 meeting are inaccurate. Miller argued that the minutes state that the committee was given permission to meet while the House was in session, but the House Journal does not reflect that permission was given for the meeting. The point of order was sustained, and the bill was returned to State Affairs.

Prior to the point of order, Rep. Sylvester Turner successfully offered an amendment to the bill which reads that each customer is entitled to, "a written contract with a service provider, on a standard form approved by the commission that includes conspicuous standardized topical headings to be identified by the commission, and that provides the consumer with sufficient information to make an informed choice of service provider."

The bill also prescribes parameters for deferred payments plans REPs must offer qualifying customers to prevent disconnections during the summer, and would prohibit disconnection of such customers. The bill also expands conditions constituting a weather emergency triggering various disconnection prohibitions.

House Distributed Generation Purchase Obligation Passes

The House also passed an amended version of HB 1243, which would compel REPs to purchase excess distributed renewable generation, and set the rate at which surplus generation must be paid. Under the bill, REPs would be required to pay surplus generation at least the fair market value, or the local market clearing price for energy at the time of day the surplus electricity is made available to the grid.

Fair market value would be set by the PUCT as a monthly or longer proxy for the market clearing price. The methodology adopted by the Commission must not allow the aggregate fair market value of surplus electricity in any billing period to be less than zero.

The mandatory pricing would apply to distributed renewable generation systems under 10 kW installed by residential customers, systems under 150 kW for churches, and under 250 kW for public schools.

REPs may charge an administrative fee to a distributed renewable generation owner on a monthly or annual basis.

The PUCT would post its fair market value calculation as well as REP offers to buy surplus generation online.

2012/2013 Capacity Costs Plummet in Unconstrained Areas of PJM

Increased capacity and lagging demand produced a clearing price of $16.46/MW-day for unconstrained areas under the PJM Reliability Pricing Model 2012/2013 Base Residential Auction, as reported by PJM in a news release.

The clearing price represents a decrease of $93.54/MW-day from the 2011/2012 Base Residential Auction.

The auction modeled the MAAC, EMAAC, SWMAAC, PSEG, PSEG-North, and DPL-South regions as Locational Deliverability Areas (LDAs), but only the MAAC, EMAAC, PSEG-North, and DPL-South LDAs were binding constraints that resulted in Locational Price Adders.

Accordingly, the resource clearing price was $133.37/MW-day for MAAC, $139.73/MW-day for EMAAC, $185.00/MW-day for PSEG-North and $222.30/MW-day for DPL-South.

The RTO as a whole and each modeled LDA, with the exception of all suppliers in EMAAC not in the PS-North or DPL-South LDAs, failed the Market Structure Test resulting in mitigation of any existing resources that failed the test in the execution of the RPM auction clearing.

Demand in the auction declined due to a 446 MW decrease in the RTO preliminary peak load forecast from 145,303 MW (adjusted to include Duquesne zone load) in the 2011/12 Delivery Year to 144,857 MW in the 2012/13 Delivery Year.

A net increase of 7,210 MW in capacity was seen, mostly due to demand response resources. The increase compared to the 2011/2012 Delivery Year auction is the largest single-year increase in available capacity since the implementation of RPM. A total of 10,463.9 MW of incrementally new capacity in PJM was available for the 2012/2013 auction, which was partially offset by generation capacity derations.

The total quantity of demand resources offered into the 2012/2013 auction was 9,847.6 MW (UCAP). Approximately 72% (7,047.3 MW) of these demand resources cleared in the auction. Of this cleared amount, 4,723.8 MW (67%) was located in the constrained regions.

PJM's Interruptible Load for Reliability product was discontinued as of 2012/2013, causing several thousand megawatts of interruptible load to offer into the auction as demand response resources.

The auction also represented the first time energy efficiency could be offered as capacity, with 652.7 MW (UCAP) offered in the auction, of which 568.9 MW (87%) cleared.

ERCOT Opposes Extra TCRs for AEP Oklaunion Plant

A new alternative proposed by AEP Energy Partners to resolve its objection to the placement of its Oklaunion plant in the West zone should be denied, ERCOT said, because it, "runs counter to basic principles of market equity and efficiency."

AEP, in its post-hearing brief (36416), suggested for the first time that it would be satisfied if, instead of changing the congestion zone configuration, ERCOT is directed to allocate, at no cost to AEP, Transmission Congestion Rights (TCRs) in an amount equal to AEP's share in the Oklaunion plant (Matters, 5/5/09).

ERCOT noted that no record evidence exists to substantiate AEP's assertions that its proposal is legal and reasonable, that it could be implemented by July 2009, or even that it would not exceed the windfall AEP would reap from placing Oklaunion into the North zone instead of the West.

Furthermore, ERCOT said AEP's alternative, "essentially would amount to a new class of pre-assigned zonal congestion rights," and that it is not clear whether AEP is proposing that its privileged congestion rights would replace or expand on the existing West-to-North TCRs.

Under a replacement approach, the TCR Proposal would displace other Market Participants' hedging opportunities; while under an expansion approach AEP's alternative would create significant unfunded market uplift, ERCOT said.

CPS Energy also opposed AEP's "last minute" alternative, arguing that consideration of the new proposal would deny other parties due process.

NiMo Gas Rate Plan Final Order Preserves MFC, Standby Sales Service Changes

The New York PSC's written order on Niagara Mohawk's new gas delivery rate plan adopts, unaltered, provisions of a joint proposal relating to retail access (08-G-0609, Matters, 5/15/09).

Under the new rate plan, separate Purchase of Receivables discount rates will be implemented for the uncollectible components applicable to the S.C. 1 and non-residential service classifications. The discount rates will reflect a 2.3% uncollectible rate for S.C. 1 and a 0.3% rate for the non-residential service classes. The same rates will appear in the Merchant Function Charge (MFC).

The discount rates will no longer include a factor to recover collections processing costs, similar to recent rate design changes at other utilities. Instead, NiMo will implement a separate charge for collections processing costs equal to $0.00419 per therm that will be assessed to ESCOs participating in the POR program. A charge of the same magnitude will be assessed to bundled customers through the MFC.

The MFC will recover the following costs, adjusted monthly.

(a) Uncollectible expense for S.C.1, S.C.2, S.C.12 and S.C.13 service classifications associated with the Monthly Cost of Gas;

(b) Gas supply procurement costs;

(c) Credit and collection costs associated with the Monthly Cost of Gas; and

(d) The return on the cost of gas in storage inventory.

Additionally, the PSC's order modifies several aspects of standby sales service for S.C. 8 customers. Standby sales service will be priced at the daily weighted average cost of gas, defined as the weighted average price of flowing supply and storage withdrawals, including variable transportation, to the citygate for that day.

The nomination deadline will be modified so that nominations will be due by 8:00 a.m. on the business day before the day the gas will be consumed. For informational purposes, by 3:00 p.m. each business day, NiMo will provide a preliminary calculation of the daily weighted average cost of gas for the previous gas day, including holiday and weekend days.

NiMo will continue to include information regarding retail access in its outreach and education plan. In addition, NiMo's welcome letter to new customers will continue to inform customers that they have the option to buy their natural gas from an ESCO and will make available a list of participating ESCOs.

IMA Suggests NYISO Demand Response Changes in Absence of Dynamic Retail Pricing

The New York ISO should evaluate alternative approaches to foster real-time economic demand response if the regulatory reforms necessary to introduce dynamic real-time pricing for retail customers do not materialize, independent market advisor Potomac Economics said in a report to FERC on demand response (RM07-19).

Potomac noted regulatory changes would be required to move retail rates to real-time pricing, and to remove the current barrier that flat retail rates pose to demand response.

Accordingly, absent such retail changes, NYISO could consider other options to provide real-time economic demand response resources the same incentives that they would have under a dynamic retail pricing regime, Potomac said. For example, one option would be a real-time price responsive demand program that would make an efficient payment equal to the difference between the wholesale LMP and the retail customer's rate. Paying this amount aligns the loads' incentives with the value of the energy to the system, and the costs could be allocated to the corresponding LSE who might otherwise receive a windfall when its load curtails, Potomac added. However, such a program would require significant efforts by the ISO to monitor and measure performance of the demand resources.

Policies to further the aggregation of retail customers into demand response programs through third parties are another alternative. The aggregation of demand resources at different meter locations is not currently permitted for ancillary services (as it is for other NYISO demand response programs), but

Potomac noted that the NYISO is working through its stakeholder process to develop market rules to permit small customer aggregations to provide ancillary services.

Briefly:

Conn. House Passes Bill to Create State Energy Authority

The Connecticut House of Representatives last week passed an amended version of HB 6510 which would create a state energy authority to run default service procurements and potentially serve as the builder or provider of last resort to meet projected electric demands.

CECG Assigns Some Conn. Default Service Contracts to Sempra Energy Trading

Connecticut Light and Power reported to the DPUC that certain of its Standard Service and Last Resort Service wholesale sales agreements with Constellation Energy Commodities Group, dated April 16, 2008, and September 6, 2006, have been assigned by Constellation to Sempra Energy Trading.

Smart Choice Energy Services Receives Md. Broker Licenses

The Maryland PSC granted Smart Choice Energy Services electric and natural gas broker licenses to serve non-residential customers in all service territories. President Iterny Joseph most recently was at North American Power Partners, focusing on demand response programs for large commercial customers (Matters, 4/28/09).

RBS Anticipates Serving Michigan Load By Q1 2010

In response to a request from Michigan PSC Staff in a docket for renewable energy compliance, The Royal Bank of Scotland said that while it is not currently serving any Michigan load, it expects to begin serving customers in the first quarter of 2010.

Entergy Texas Transition to Competition Hearing Set

Hearings regarding Entergy Texas' updated transition to competition plan are to be held September 29-30 under an updated schedule released by an ALJ Friday (33687). A technical conference with ERCOT and SPP is set for June 2.

ICC Seeks Procurement Comments

The Illinois Commerce Commission is accepting comments regarding the spring 2009 default service supply procurements conducted by the Illinois Power Agency. Initial comments are due June 1.

CenterPoint to Delay Baytown AMS Deployments Until Latter Part of 2010

CenterPoint Energy said it has rescheduled deployment of approximately 40,000 advanced meters and associated communications infrastructure for Baytown, Texas, from early 2010 to the latter part of 2010, to improve deployment efficiencies and allow sufficient time to install communication infrastructure. The change will not impact the total scheduled number of advanced meters deployed for 2010. CenterPoint said that as of April 30, 2009, 10,251 advanced meters have been installed. Separately, Oncor reported that it has installed 200,976 advanced meters as of April 30.

International Power America, Subsidiaries Reach Settlement on Governor Response NOV

Hays Energy Limited Partnership, Midlothian Energy Limited Partnership and ANP Funding I, LLC would pay an administrative penalty of $2.5 million to resolve PUCT Staff's notice of violation regarding various ERCOT Protocols and Operating Guides, under a settlement with Staff filed Friday (34738). Collectively, the three entities accept liability for violations ranging from 2004 through 2006 concerning failure to put governors in service to allow them to respond to changes in system frequency, failure to inform ERCOT of impaired governors, and failure to timely respond to an ERCOT request for information. Staff was originally seeking more than $6 million in penalties. International Power America, a holding company that directly owns all three entitles, is a party to the settlement but does not admit liability for any violation alleged by Staff, and is not required to pay any part of the penalty.

FERC Approves NYISO Tariff Changes for Stored Energy Resources

FERC approved, unmodified, tariff revisions from the New York ISO to integrate energy storage devices into NYISO's day-ahead and real-time regulation service markets (Matters, 3/16/09).

PUCT Issues Final Language for POLR Rule

The PUCT posted adopted language for its final new POLR rule in docket 35769 (Matters, 5/8/09).

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was actually higher versus the year-ago period, resulting in the aforementioned gross profit gain.

Comparing RCEs as of March 31, 2009 to the level as of December 31, 2008, gas RCEs were down 43,000 from 563,000, and electric RCEs down 17,000 from 91,000.

Average in-contract customer attrition increased to 32% for the 12 months ended March 31, 2009, from 26% for the twelve months ended December 31, 2008.

Chief among the reasons for higher attrition were amendments to MXenergy's revolving credit facility which placed formal constraints on the term and type of contracts that the retailer could offer customers. In particular, MXenergy's ability to offer long-term fixed rate products to new customers was severely limited. The amendments also hindered MXenergy's ability to offer different options to customers notifying the marketer of their intent to terminate their contract before its termination date. The existing credit facility expires July 31, 2009, and MXenergy is working to execute a new facility without such restrictions.

Falling commodity prices since the fall of 2008 exacerbated attrition, as customers sought to move to lower market rates, and MXenergy's offerings were hampered by its facility arrangement.

Additionally, MXenergy reduced sales and marketing expenditures to conserve cash. Advertising and marketing costs for the nine months ending March 31, 2009 were trimmed to $1.7 million from $3.9 million in the year-ago period. MXenergy has also scaled back its use of certain sales channels, which had a negative impact on brand awareness and new customer acquisitions during the nine months ended March 31, 2009. As its liquidity position improves, MXenergy expects to return to its customary sales and marketing practices and channels.

Furthermore, deteriorating economic conditions during fiscal year 2009 resulted in credit-related attrition that was higher than historic levels, particularly in markets without Purchase of Receivables, such as Georgia and Texas, as well as in the Ohio, Michigan and Indiana natural gas markets. To mitigate exposure, MXenergy said it initiated aggressive actions to disconnect service to delinquent customers, and also implemented enhanced credit standards for all existing and prospective customers, which limited acquisitions. Credit-related attrition was particularly high in Georgia, partially due to expected credit quality issues within the customer book acquired from Catalyst Natural Gas last fall.

Among other provisions associated with MXenergy's amended credit agreement is that any acquisition of customer portfolios or operations of other companies is prohibited. Under a prior amendment, acquisitions were allowed upon the approval of lenders.

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However, the proposed decision holds that after the market liquidity issue has been satisfactorily mitigated with the implementation of the Standard Capacity Product tariff, along with any program refinements that may be necessary to coordinate with the Standard Capacity Product tariff, "it will be appropriate to further evaluate whether to convert year-ahead forecasts to the current customer method," with such conditions potentially being met in 2011.

A proposal from Sempra Energy Solutions to address the impact of customer migration on local Resource Adequacy obligations would be deferred until the 2011 compliance period under the draft, though the proposed decision backs the core principle of Sempra Energy Solutions' proposal -- that local Resource Adequacy adjustments would be limited to documented instances of migration.

Currently, local Resource Adequacy procurement obligations are established annually for a 12-month compliance period. Thus, when an LSE loses a customer to another LSE during the compliance period, it temporarily remains saddled with Local Resource Adequacy procurement costs associated with that customer. At the same time, the LSE that gains the migrating customer has no obligation to procure capacity on behalf of that customer for the remainder of the compliance year.

The draft agreed that the current construct shifts compliance costs to the losing LSE, counter to the PUC's policy to equitably allocate the cost of generation and prevent cost shifting. Sempra Energy Solutions noted that the current program may provide an unjustified competitive edge to new LSE entrants, who gain customers without an attendant local Resource Adequacy obligation.

Sempra Energy Solutions proposed that local capacity obligations be assigned from the losing LSE to the gaining LSE for customers with demand meters, to mitigate the potential competitive advantage.

Despite recognizing the problem, the proposed decision declines to adopt any change for 2010, principally because the pending Standard Capacity Product is essential to developing a liquid capacity market to facilitate transactions resulting from the shifted local obligations. Additionally, the draft said that the issue of how to measure a migrating customer's load needs to be further explored.

The proposed decision would establish further workshops, and said it intends for the Commission to adopt a local capacity obligation assignment program for 2011. The draft suggests that only migrating customers with demands in excess of 3 MW should be tracked for the initial year, and also holds that it would be improper to require or encourage utilities that are long on local Resource Adequacy capacity to sell that capacity to other LSEs, but not impose the same provision on competitive LSEs.

Additionally, the draft holds that, under certain circumstances, the allocation of Cost Allocation Methodology capacity credits to LSEs under D. 07-09-044 will be performed on a monthly basis, rather than quarterly. The switch to monthly allocations would be triggered when an individual service territory has two or more operational Cost Allocation Methodology contracts. Service territories with one operational Cost Allocation Methodology contract would continue to have quarterly reallocations of Cost Allocation Methodology credits. If a reallocation of credits would result in no change greater than 0.5 MW for any LSE, credits would not be reallocated that month.

The proposed decision would reject the Alliance for Retail Energy Market's recommendation to end the use of Maximum Cumulative Capacity (MCC) Buckets. The MCC buckets were established early in the Resource Adequacy program to ensure that LSEs do not over-rely on resources with limited availability to the point that CAISO would not be able to reliably operate the grid with Resource Adequacy resources. The buckets represent the maximum cumulative percentage of an LSE's procurement obligation that can be met with use-limited resources (ULRs) and Resource Adequacy contracts that provide less than "7x24" hours per week availability. Though AReM argued changes in the capacity program have made the buckets superfluous, the draft decision would find that the buckets continue to have important reliability benefits.

Over the objections of AReM, the draft would also require LSEs to use the load impact (LI) protocols for demand response resources in D. 08-04-050 to measure the Resource Adequacy contribution of demand response. AReM had argued that the load impact protocols, designed to measure the cost-effectiveness of utility programs, are not appropriate for the demand response resources of competitive providers, and that they would also place a burden on competitive providers.

Furthermore, the proposed decision would affirm that demand response capacity credits from utility programs should be allocated to LSEs in proportion to the funding that their respective customers provide toward the demand response programs. Thus, as bundled customers pay for most of the programs, credits will be allocated to bundled customers only.

AReM had argued that credits should be allocated based on the proportion of customer participation in the utility demand response programs. As some customers on competitive service participate in the utility demand response programs (for which they are eligible as delivery service customers), AReM contended that competitive providers should receive associated capacity credits from the programs. However, the draft finds that it would be, "inequitable to bundled service customers to assign [demand response] capacity credits to LSEs on the basis of who participates in the [demand response] program, without regard to how it is funded."

The draft would slightly adjust deadlines for the 2010 compliance cycle given new deadlines in the California ISO's Market Redesign and Technology Upgrade. Under the draft, preliminary local procurement showings shall be made on September 18, 2009 and final compliance showings for both local Resource Adequacy and System year-ahead Resource Adequacy shall be due on October 29, 2009. The draft would also encourage advance reporting by October 9 through an optional supplemental reporting procedure. CAISO has agreed to issue a revised deficiency notice in mid-November that reflects the final procurement information provided by LSEs at the end of October.

Recognizing that the current Resource Adequacy rules "significantly" overstate the dependable level of intermittent generation that is available during peak hours, the draft would revise rules for counting the net qualifying capacity of intermittent wind and solar power generation. To more accurately reflect the actual performance of such resources during peak load conditions, the draft adopts an "exceedance" method for calculating the net qualifying capacity of intermittent resources that explicitly takes into account very large variances in output during peak periods. Under the recommended exceedance factor of 70%, the qualifying capacity of a wind or solar resource would be equal to the minimum output achieved by the resource for at least 70% of the hours in the data set of historical generation for each month.