Energy Choice Matters

June 3, 2008

Calif. Power Agency Warns CAISO Is Compromising MRTU Testing to Hit Go-Live Date

Pressures associated with the unofficial "target" commercial operational date of the California ISO's Market Redesign and Technology Upgrade (MRTU) may compromise the market readiness testing process, the quality of market solutions and the availability of required functionality, the Northern California Power Agency reported to FERC (ER06-615).

NCPA is concerned that the CAISO, "will be pressured to select a date that Market Participants currently view as unattainable, and will push through necessary testing without getting the results that validate functionality."

NCPA wants CAISO to report greater specifics in monthly MRTU status reports, and urged FERC to schedule a "safety net" technical conference in August to provide an opportunity to raise remaining concerns, assuming the current Oct. 1 go-live date isn't pushed back.

NCPA stresses that CAISO staff have been challenged with the "near impossible" task of advancing systems that are not fully tested, and their efforts have been, "nothing less than heroic," at times, NCPA said.

Unfortunately, despite those efforts, NCPA continues to fear that the CAISO schedule is dictated by the pressure of a projected implementation date rather than by a schedule that is focused on real readiness assessments.

Forced advancement of the simulation process to the next step when the last step did not work as planned produces ineffective results and places pressure on staff to advance the simulation regardless of whether the functionality is working or not, NCPA noted.

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Universal Wants Michigan PSC to Inform Customers of GCR Costs, Gas Forecast

Universal Gas & Electric formally requested that the Michigan PSC staff inform customers of current utility GCRs when they contact the PSC with complaints regarding UG&E (U-15509).

It's a request UG&E has made before in pervious filings related to the Commission's investigation of its marketing practices (Matters, 5/6/08). UG&E notes that customers, due to negative and inaccurate news reports, are calling the PSC to cancel UG&E contracts despite, in some cases, the UG&E price now being lower than the utility rate due to the rise in natural gas prices.

If customers knew that MichCon and Consumers are currently charging $1.005 and $0.92 per Ccf respectively, in comparison to UG&E's contract prices of $0.999 and $1.049 per Ccf, their concerns would presumably diminish, UG&E asserted. In April, UG&E cancelled contracts for 27 customers in the MichCon territory whose contracts had a rate of $0.99/Ccf and who will now pay the utility GCR of $1.005/Ccf.

"Providing customers with accurate, factual information would lessen everyone's work load and at the same time protect customers from making important financial decisions based on incomplete and inaccurate information," UG&E told the Commission.

UG&E also urged staff to share with consumers the Commission's view, stated in its summer energy appraisal, that gas prices are likely to continue to rise.

UG&E pointed to a part of the report which stated that, "Natural gas prices in 2008 are expected

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FERC Approves Capacity Export Charge For PJM

FERC accepted PJM's proposed capacity export charge (ER07-1050) in which an export customer that draws capacity from a constrained area is required to pay the capacity congestion charge that its export helped create.

Under PJM's existing RPM protocols, FERC observed, the costs that may be incurred in a constrained Locational Deliverability Area as a result of a given export are borne only by the load serving entities in that area. As a result, export customers are currently insulated from the costs attributable to those transactions.

FERC determined that an export customer with firm transmission service should receive a credit against higher locational capacity prices based on its firm transmission service.

The Commission rejected arguments from AEP and Constellation that the export charge amounted to a prohibited through-and-out rate.

FERC explained that PJM's border rate for point-to-point transactions leaving PJM, under schedules 7 and 8 of the PJM OATT, remains inapplicable to transactions with a delivery point within the boundaries of the Midwest ISO. However, firm transmission service between PJM and the Midwest ISO remains subject to congestion charges, and a capacity export charge is similar to such a charge, FERC concluded.

"A capacity export charge is not based on an arbitrary corporate boundary but rather on a capacity resource price differential arising from the reliability limitations within PJM. These reliability limitations equally confront internal and external transactions that must pass into capacity constrained PJM zones," FERC ruled.

Contrary to the assertions made by AEP and Constellation, the export charge can be hedged through capacity transfer credits (CTRs), FERC held.

EILS Encouraging New Demand Response, ERCOT Reports

Projected year-to-date costs for ERCOT's Emergency Interruptible Load Service (EILS) program are $12 million, the ISO told the PUCT in an annual report on EILS (27706).

Since EILS is deployed only in Step 3 or Step 4 of the Emergency Electric Curtailment Plan, which ERCOT has not reached since procuring EILS megawatts, ERCOT reported it is premature to determine whether the QSEs and EILS Resources providing EILS would have performed according to their requirements, or whether an EILS deployment would have served its intended purpose of providing a tool for ERCOT Operations to avoid shedding firm load during an emergency condition.

Still, EILS has brought new demand response resources into the ERCOT market, ERCOT noted, a secondary goal of the program.

Some 63% (164 MW) of EILS capacity committed in the Business Hours Time Period in the February-May 2008 Contract Period were not registered Loads Acting as a Resource (LaaRs), and all 185 MW registered in non-business hours for that contract period were not LaaRs, thus representing new demand resources.

For the June-September 2008 Contract Period, 68% (210 MW) of business hour EILS were not registered LaaRs.

And LaaRs' participation in EILS does not necessarily imply that available demand response resources are simply "migrating" to a different service, ERCOT stressed, since there is a 1,150 MW cap on Responsive Reserve Service that can be provided by LaaRs, but nearly 2,100 MWs of LaaRs registered.

PJM Clarifies Proposed Treatment of Generation Retirements, Withdrawals in Interconnection Queue

PJM's proposed treatment of generation retirement announcements and subsequent withdrawals that occur prior to the queue date of a specific interconnection customer's project is consistent with how it views retirements in terms of transmission planning, the RTO assured FERC (EL08-55).

Exelon had questioned whether such treatment was inconsistent (Matters, 5/19/08), since PJM Manual 14B states PJM will continue to plan the system to accommodate retirement of a generator even if the generator withdraws its retirement request.

PJM clarified that it only continues to plan the system to accommodate retirement of a generator when there is not "compelling evidence" in addition to the withdrawal of the retirement notice that the generator actually will remain in service. Examples of such compelling evidence would be if the generator bid into and cleared the Reliability Pricing Model auction or if the generator had made significant new investments to upgrade the facility prior to withdrawing its retirement notice, PJM explained.

The mere statement by a generator that it wants to withdraw its retirement notice by itself is insufficient for PJM to conclude that the generator actually plans to remain in service, and thus PJM must still plan for the unit's retirement for reliability purposes.

PJM clarified that it will apply the same policy to the interconnection process, and will consider the withdrawal of a deactivation notice a restudy trigger only when there is compelling evidence that the withdrawal of a deactivation notice is credible and the generator actually will remain in service.

PJM also clarified that in the event that a deactivated unit desires to retain its existing Capacity Interconnection Rights for any extended period, it must submit a new interconnection request within one year of its deactivation date, responding to a concern raised by FirstEnergy.

If a generator that has deactivated does not submit a new interconnection request within one year of its deactivation, the generator would need to submit a new interconnection request in order to reactivate and then proceed through the interconnection study process just like any other new entrant. The reactivating generator in such a case would be responsible for any upgrades required to accommodate the reactivation.

PJM argued that other comments on its petition concerning upgrade costs, from FirstEnergy and the New Jersey Board of Public Utilities, amount to pleas to relitigate FERC's Neptune decision on interconnection rules, and should not be considered.

Briefly:

PUCT Sets Schedule for CenterPoint AMIN Plan

The PUCT set a procedural schedule for CenterPoint Energy's advanced metering information network (AMIN) in docket 35620, including a technical conference on June 10 and a settlement conference June 18.

ICC Schedules Meeting on Summer Supplies, Utility Procurement

The Illinois Commerce Commission's Electric Policy Committee will meet at 1:30 p.m. Wednesday in Chicago with electric utility executives and RTO representatives to discuss electric energy supplies for the year. The Commission also expects to discuss ComEd and Ameren Illinois' recent electric procurement activities and the effect on preparedness for the peak cooling season.

Dayton Power & Light Asks for Bill Change Regarding Location of Stabilization Charges

Dayton Power and Light asked PUCO to approve a billing change to show the Rate Stabilization Surcharge among the generation service charges to reflect the removal of the RSS from distribution charges into a non by-passable generation rider charge (08-0651-EL-UNC). The RSS currently appears on the distribution portion of the bill.

Electric Advisors Wants D.C. Broker License

Electric Advisors applied for broker license from the District of Columbia PSC (EA08-1). Electric Advisors, which holds a broker license in Maryland, would broker C&I customers.

EnerNOC Preferred Provider of Calif. Water Agencies

California Water Agencies selected EnerNOC as a Preferred Provider which will allow the state's water agencies to enroll in EnerNOC's demand response programs.

Integrys Wins Family Dollar Management Contract

Family Dollar selected Integrys Energy Services to provide comprehensive energy management services for its 6,000-plus retail stores to mitigate volatility, reduce costs, and manage energy sourcing.

ConsumerPowerline Choice of Vt. Utility

Central Vermont Public Service picked ConsumerPowerline as the exclusive provider of demand response solutions to its customers in the area affected by the Coolidge Connector project. ConsumerPowerline will be the sole demand response provider for CVPS's Vermont Reliability Program through May 2011 to bridge the reliability gap until the Coolidge Connector line enters operation.

Comverge Selected for Virginia Power Pilot
Dominion Virginia Power chose Comverge for technology to run a pilot residential demand response program in which Dominion will deploy smart programmable communicating thermostats and intelligent load control switches for 2,000 homes in Northern Virginia, Richmond and the Hampton Roads areas. Comverge's load management system will send a communication signal to the demand response devices installed at the homes to cycle air conditioners. The system also allows residents to program and control the temperature setting of their home thermostats using the Internet.

ECS Streamlines Operations with Ziphany
Energy Curtailment Specialists contracted Ziphany to implement its enhanced Notification Module for the more than 3,000 demand response customers of ECS throughout the U.S. and Canada. Ziphany's module allows automated notifications of demand response events, which previously required ECS to commit staff to contacting customers.

MRTU Testing ... *from 1*

If MRTU is implemented without certainty that systems are functioning properly, the results could be "catastrophic" for the market, NCPA cautioned.

The Market Simulation process, "has strayed far afield from the foundational elements set forth in the Guidebook," NCPA reported.

Rather than adhering to the structured process outlined in the Guidebook, the CAISO has revised the Market Simulation process and schedule on a seemingly weekly basis, NCPA claimed, with revisions apparently made to meet the expected "Go-Live" date rather than to successfully test all necessary functionality.

NCPA argued that five weeks of market simulation activities leading up to a March 21 pause in testing were a "disaster," punctuated by almost daily patches and workarounds to resolve outstanding testing failures.

NCPA believes the failure resulted from a testing process that did not adhere to the entry/exit criteria established by the CAISO and Market Participants, both in the Guidebook and in planning sessions, and the misguided efforts of the CAISO to accelerate the market simulation process even though the MRTU systems were simply not ready.

Of particular concern to NCPA is the lack of CAISO settlement testing that has taken place to date. Only 33 of the 123 CAISO settlement charge types have been validated, according to CAISO's May status report.

NCPA has been able to validate only a limited subset of the 33 charge types through an integrated Bid-to-Bill process.

If the problem is not resolved with sufficient time to fully test within the market simulation process, it could have "extraordinary" financial consequences for the market, NCPA warned.

"The current markets continue to be plagued with the impact of retroactive settlement adjustments and litigation stemming from the California market meltdown that has resulted in significant costs to California consumers. Market Participants would strongly prefer that a need for frequent retroactive adjustments not be embedded in the system at start-up," NCPA noted.

NCPA pleaded for at least three months (and preferably six) of unstructured market simulation for Market Participant Readiness, but noted the latest CAISO schedule would only include 1.5 months of such testing. NCPA thinks the shorter simulation period, which lets Market Participants test their systems against a functioning CAISO system (which does not yet exist), will result in start-up problems that could easily have been prevented and which are likely to result in negative impacts to California consumers.

NCPA told FERC that Market Participants and CAISO were engaged in disputes over how to categorize several problems. MRTU testing cannot move onto later stages until items of "critical" or "very high" importance to the market are resolved, but NCPA thinks the ISO is relegating such items to only "high" importance, since such designation does not force the ISO to delay moving onto a later testing phase.

For example, all Market Participants must be able to submit bids for all resources into the market and receive accurate results from the MRTU systems, NCPA noted. The MRTU systems are still struggling with the submission of bids and schedules and retrieval of data from the Day Ahead and Real Time markets, NCPA reported, a process it views as critically important. But in a number of cases, variances associated with that limited ability are assigned the lower priority ranking of "high," NCPA told FERC.

As a result of many of the outstanding variances, which impact the proper submission and retrieval of bids within the MRTU systems, NCPA has not had one day within the market simulation in which all bids could be submitted and retrieved as designed, it reported.

UG&E Suggestion ... from 1

to be higher than in 2007," and, "The price of natural gas for residential customers including the cost of gas, distribution and customer charges for 2008-2009 could be up as much as 19 percent over last year."

Customers would also benefit from knowing what utility GCRs were at the start of the year versus the current rate, so consumers could judge how much utility rates have climbed, UG&E suggested.

That information would provide customers with a reference by which to compare the fluctuating GCR prices with UG&E's fixed price. "Only by being fully informed will Michigan consumers be in a position to make an informed decision regarding the appropriateness of UGE's natural gas prices," UG&E argued.