Energy Choice Matters

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Integrys Expects Double Digit Growth for Competitive Unit

Integrys Energy Services expects expansion into mature U. S. and Canadian energy markets is to grow core earnings by 10-15%, Larry Weyers, CEO of the marketer's parent Integrys Energy Group, told analysts on a conference call.

Retail and wholesale natural gas volumes grew 14% year-over-year at Integrys' competitive unit, excluding an additional 44 bcf of forward contracted natural gas acquired when WPS Resources bought Peoples Energy.

Forward contracted wholesale electric volumes grew 39% while retail power sales are up 102% overall and 38% when excluding 7 million MWhs gained from Peoples Energy.

Integrys Energy Services delivered 14.6 million MWhs in 2007 -- a 10 million MWh increase from 2006.

Illinois accounts for 57% of delivered volumes and 44% of forward volumes at Integrys Energy Services. The retailer made the biggest move in Texas, where its forward volumes are at 28% versus 2007 delivered volumes of 7%.

Integrys Energy Services is to focus on responding to customers' increasing interest in renewable power and clean fuels, Mark Radtke, the competitive unit's president, told analysts.

The retailer added 17 new account executives last year outside of the merger.

Integrys Energy Services' electric margin increased $43.9 million and its natural gas margin increased $8.5 million, in after tax dollars.

Gains were partially offset by nearly $11 million in higher operating and maintenance expenses at the marketer, including higher payroll, benefit costs and consulting fees related to continued business expansion, mostly the merger with Peoples.

Its fourth-quarter earnings grew $48.4 million to $49.1 million.

For parent Integrys Energy Group, utility rate hikes and higher regulated sales helped quadruple fourth quarter earnings to $85 million versus $21 million in the prior year's quarter.

Oncor Suggests Socialized Costs to Fix Inaccessible Meters

Oncor has a novel idea to ease ongoing problems from new meter reading rules at the PUCT – socialize the costs of upgrading customers' meters (docket 35280).

This summer the PUCT implemented rules that prohibited estimated meter reads for more than three consecutive months, a policy designed to help customers avoid large true-ups. But since many estimated reads are caused by inaccessible meters, the PUCT allows TDSPs to disconnect customers who refuse to make the meter accessible, relocate the meter at customer expense or install a meter capable of being read remotely at customer expense. Disconnect notices prompted by inaccessible meters have received lots of attention in the Houston media.

For Oncor, only about 0.03% of customers face disconnection for having an inaccessible meter -- less than 1,000 customers. Still, that's too many for the wires owner, since those customers are paying their bills on time.

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CL&P Suffers Another Billing Snafu

About 2,000 Connecticut Light & Power customers did not get their January bill due to a software error at the utility.

Now the DPUC is trying to fix the situation (docket 08-02-06).

Billing issues plagued CL&P earlier this summer when customers complained of higher bills from faulty meters. Not helping the current climate is Connecticut Natural Gas which is dealing with politicians furious over the utility's months of underbilling and decision to send customers bills for hundreds of dollars to catch up in one month, all without notifying the DPUC.

CL&P has offered to allow affected customers to pay their January bills through the end of the calendar year without late payment charges being assessed.

The DPUC told CL&P to suspend all collection activities for the unbilled usage pending the completion of DPUC's investigation. The precise terms and conditions of payment will be determined by the Department.

The DPUC wants to know if the billing problems are related to CL&P's proposed C2 customer information system upgrade.

CL&P is to tell the DPUC the total amount of the billing error and whether CL&P can ensure there are no other customers affected.

The utility is to report on how such problems won't be repeated once its C2 system is operational.

PG&E Plant Needs Specific Cost Cap, Marketers Say

The Alliance for Retail Energy Markets and Western Power Trading Forum want a proposed decision on Pacific Gas & Electric's Colusa Power Project to include a specific cost cap (07-11-009).

The 657 MW combined cycle plant was originally being built by E&L Westcoast Holdings after an RFO, subject to an initial capital cost price cap, and was to be run by PG&E once completed. E&L decided to terminate its contract and PG&E wants to finish the plant itself.

But AReM and WPTF have a "strong concern" PG&E cannot possibly complete the project at the cost cap given today's greatly inflated raw material prices.

The marketers are "puzzled" by PG&E's assurances it can complete the project at the cost cap when economics suggest such a feat cannot be done.

Although the proposed decision does subject PG&E to the capital cost cap established in the RFO process, that ruling is imprecise because the RFO Decision does not, in fact, contain the phrase "cost cap" anywhere in it, AReM and WPTF noted.

Rather the RFO decision finds the fixed contract costs for the Colusa Project to be reasonable and provides that the fixed contract costs, other than incentive payments, shall be included in the initial annual revenue requirement.

Thus the PUC needs to set a specific dollar amount on the cost cap, the marketers argued.

AReM and WPTF warned that if the project is completed for more than the cost cap, "both competition and faith in the competitive process will be unalterably harmed."

PG&E's entire evaluation of its RFO would be called into question, and the marketers wondered if other projects rejected by PG&E would have been better choices if the cost cap is exceeded.

AReM and WPTF also want the proposed decision to make sure PG&E does not skirt the cost cap by categorizing higher costs as "operational enhancements."

EnerNOC Warns Calif. Proposal Would Chill Demand Response Market

A proposed decision that would reject six demand response contracts procured by Southern California Edison would send a signal to demand response providers that they aren't wanted in the state and "would be a devastating setback [for] California's goal of increasing reliance [on] clean, economic, peaking, dispatchable, and ramping demand-side resources," EnerNOC told the California PUC (07-10-013).

The proposed decision accepts only two of eight demand response contracts because only two were found to be cost effective by the ALJ. The ALJ also did not find an immediate reliability need for the rejected contracts.

But the proposed decision ignores a Commission directive only six months ago for SCE to procure more demand response resources without creating a cost-effectiveness criteria for the resources, EnerNOC pointed out.

The PUC had found that demand response contracts that were competitively procured would be a reasonable reflection of the market, EnerNOC added.

The proposed decision also improperly rejects the PUC's stated goal to meet 5% of system load with demand response, EnerNOC reminded.

The proposed decision, "relied on a questionable cost-effectiveness analysis, failed to fully account for the environmental benefits of DR, and ignored the innovative DR resources offered by the contracts," EnerNOC said.

The harm to the competitive demand response market is exacerbated because the PUC continues to approve utility-run programs that are not competitively selected, are not subjected to the cost-effectiveness analysis retroactively applied to the instant contracts, and do not contain penalty provisions for non-performance, EnerNOC pointed out.

EnerNOC criticized the ALJ's logic that SCE doesn't need the demand response capacity since it has met its 2008 capacity obligations. First, SCE must meet resource adequacy rules, so it never needs capacity currently (or otherwise it would be violating mandates). But just because SCE is meeting its current obligations doesn't mean future resources aren't needed, EnerNOC noted. Following the ALJ's logic, power plants could never be built because SCE would never have a "current" need for them based on the current year, EnerNOC observed.

EnerNOC also questioned the assumption that California will experience another mild summer and not need additional resources or local emergency capacity. The demand response aggregator explained that the contracts are needed for 2009, but must be implemented now for them to be available in the future as they ramp up over time.

The Division of Ratepayer Advocates, though, thinks the proposed decision didn't go far enough and should have included performance-based contract terms that will help reduce ratepayer risk for the two contracts approved.

Pepco Energy Services Slams D. C. Affiliate Proposal

Proposed affiliate rules would create an unlevel playing field among retail suppliers, Pepco Energy Services (PES) told the District of Columbia PSC (FC 1009).

PES complained that under the rules it, as a utility affiliate, would be forced to include lengthy and confusing disclaimers on its marketing materials informing customers that its rates are not set by the PSC. But such a statement wouldn't be required on competitors' ads, PES noted, suggesting that only PES' rates were unregulated.

PES argued that the PSC doesn't have authority to implement many of the proposed restrictions.

But the Office of People's Counsel thinks the rules are needed because the "lines of distinction between the regulated entities and the unregulated subsidiaries have become increasingly blurry, as these entities attempt to make inroads into new markets."

Consumers are often left to figure out who is providing the service and often ask what is the difference between PEPCO and PES, or Washington Gas and WGES, OPC noted.

Washington Gas asked the PSC to clarify that restrictions on affiliates' use of utility billing would not apply to the space utilities allocate on bills for all competitive suppliers using utility consolidated billing, provided all suppliers receive equal treatment.

Briefly:

RESA Wins More RFIs in Nstar Green

CONTINUING COVERAGE

The Retail Energy Supply Association and Direct Energy Services won a procedural battle in the Nstar green case (07-64) that allows the retailers to issue follow up RFIs, file expert testimony and prepare an expert report on the reasonableness of Nstar's contract prices for wind power, a hearing officer ruled (Matters, 2/12/08). RESA received confidential information from Nstar much later than other parties in the proceeding due to procedural disputes and its request for more discovery and testimony was prompted after reviewing utility data which became available January 22. Retailers' additional activities have the potential to enhance the record, the hearing officer noted.

PSEG Faults PJM Credit Focus
CONTINUING COVERAGE

PJM's solution to recent defaults improperly focuses on increasing collateral instead of creating sufficient initial credit requirements, PSEG told FERC (Matters, 2/15/08). PSEG thinks that PJM focuses "on risky transactions rather than on risky members," raising the costs to members with sound credit but failing to protect members against other members with shaky credit (docket ER08-520). PSEG compared the situation to auto loans, noting that individual credit history – not the structure of the loan – determines approval. "The answer to a rash of car loan defaults would not be to make everyone pay the same high interest rate but to instead adopt a more rigorous analysis of credit history at the outset," PSEG noted. PJM, PSEG argued, is focusing on raising collateral requirements for all members, regardless of whether they are investment grade companies or an LLC with no financial backing. Yet investment grade companies are not credit risks even if they participate in "risky" Financial Transmission Right counterflow transactions, PSEG claimed.

Calif. PUC to Look at Long-Term Procurement
FIRST LOOK

The California PUC opened a rulemaking to update its policies for utilities' long-term procurement plans (R.08-02-007). Among Phase I issues to be discussed are standardized resource planning practices, interim standards to evaluate the uncertain costs of greenhouse gas regulations; a methodology to quantify energy efficiency in the California Energy Commission's forecast; methodologies to estimate firm capacity from demand-side resources; a customer risk preference study; and the impact of the implementation of the CAISO's market redesign and technology update (MRTU) on procurement. Phase II the rulemaking is to examine two key policies impacting marketers: system versus bundled resource needs (and accompanying cost allocation), and refinements to the bid evaluation process to ensure fair competition between power purchase agreements and utility-owned generation bids, and "alternatives to the competitive market approach where competition cannot be used to reach equitable and efficient outcomes."

Existing RG&E Russell Station to Close in May

Rochester Gas & Electric's Russell power plant is to shut down after scheduled grid upgrades are completed under a settlement between RG&E and AG Andrew Cuomo. However, the settlement only addresses the operation of the existing coal units and does not address whether RG&E can repower the station – an issues being hotly contested in the PSC's review of Energy East's takeover by Iberdrola. RG&E did agree with the AG that should it repower the plant (as it wishes to do) it will do so with natural gas, something it had previously promised. Grid upgrades are scheduled to be completed in May, at which time the PSC staff expects RG&E to divest or close the plant, without repowering it, due to the PSC's policy limiting utility ownership of generation. The plant had been exempted from divestiture because prior to grid upgrades the plant served a load pocket.

EnerNOC Has Tweaks for SDG&E Peak Price Plan

EnerNOC wants to make sure customers on a San Diego Gas & Electric critical peak pricing (CPP) product can participate in Day-of demand response programs, such as the Day-of Capacity Bidding Program (07-01-047). Customers should be able to participate in both programs because Day-of programs can provide dispatchable demand response in response to system-wide shortages and local emergencies, EnerNOC noted. CPP does not have this dispatchability feature nor can it be called on the day of an emergency. EnerNOC also urged the PUC to allow customers to opt-out of CPP after an initial 45-day election window if customers are moving to another demand response product. The 45-day window starts in April and EnerNOC is concerned customers may not receive meaningful feedback to evaluate CPP in just 45 days, especially so early in the cooling season.

D. C. PSC Rolls Out Draft Interconnection Rules

The D. C. PSC proposed small generator interconnection rules in FC 1050 to establish the technical and procedural requirements for small generators to connect and operate in parallel to the EDC's grid. The rules would apply to generators under 10 MW that aren't subject to PJM interconnection rules.

Linkin Park Carbon Neutral

Energy Analytics, a New York-based energy services company, was selected by rock band Linkin Park to provide RECs to offset the carbon associated with the band's power needs at a February concert at Madison Square Garden.

World Energy Bundles Green Auctions

Online broker-consultant World Energy Solutions has bundled its green offerings into the World Green Exchange, an auction platform for environmental commodities. The online auction combines sales of green power, RECs, Verified Emission Reductions and carbon offsets.

BG&E Picks DR Vendor

Baltimore Gas & Electric picked Cooper Power Systems to provide a system for peak demand reduction for residential customers. Cooper expects the project will represent $42 million in revenue over the period 2008-2011 and, when expanded to full capacity, provide more than 600 MW by 2011.

Oncor Meters … From 1

Oncor is also deploying smart meters across its grid, and noted it doesn't make sense for customers with inaccessible meters to shoulder the costs of upgrading to a meter that is soon to be replaced by smart metering technology.

Thus Oncor wants to provide remotely read meters at "no cost" to the customer by allowing Oncor to recover costs for the meter via its Advance Metering surcharge in Subst. R. 25.130.

Oncor would not pay for monthly costs associated with the remote meter.

Oncor also wants to use its advanced meter surcharge to provide interim time of use meters for REPs. Several REPs have told Oncor they want to implement time of use programs by the middle of this year, but Oncor's current meters won't support the data needs of time of use products. Normally REPs would have to pay for new meters.

Oncor doesn't want to delay important time of use programs during the period of time it will take to implement its smart grid, it told the PUCT.

"Oncor submits that it is beneficial to the public for REPs to begin to offer time differentiated rates to gauge public reaction prior to full implementation of [smart meters]. Implementation of time of use rates in advance of implementation of [smart meters] will allow the market to incorporate lessons learned from their interim time of use programs into more desirable time of use options once [smart meters are] deployed," the TDSP said.

Oncor also sees its suggestion leveling the playing field among customers since smart meter deployment will take time to roll out across Oncor's territory. Allowing customers scheduled for later installation of smart meters to get a "free" time of use meter in the interim will ease any potential competitive advantages some customers may receive from greater pricing options.

Oncor suggests containing costs by limiting the time of use meter plan to 5,000 meters, with no more than 1,500 meters being installed for any one REP.