Energy Choice Matters

January 20, 2009

Maine Co-op Asks for Longer Aggregations, Exception to Competitive Bidding

Dirigo Electric Cooperative recommended that proposed rules to implement standard offer aggregations at Maine consumer-owned utilities (munis/co-ops) be modified to allow aggregations to be awarded outside of a competitive bid process, in the case of an electric cooperative owning generation or entering a PPA with a generator, the cooperative group said in comments at the Maine PUC (2008-463).

Recent legislation allows municipal and cooperative utilities to aggregate their load for the purpose of providing standard offer service to customers within their service territories (Matters, 7/16/08).

Under the PUC's proposal, a cooperative could arrange for a retail standard offer load aggregation provider, or could itself act as the retail provider of the standard offer load aggregation service. Per the PUC draft, "[t]he cooperative must choose either a wholesale or retail provider through a competitive bid process."

Dirigo, which is composed of several of the state's munis and co-ops such as Eastern Maine Electric Cooperative and Houlton Water Company, recommended that a cooperative not be required to choose either a wholesale or retail provider through a competitive bid process if the cooperative owns generation or has a PPA with a generator.

Without additional language, Dirigo noted the competitive bid requirement could prevent a cooperative from using its own generation (or contracted generation) to supply the standard offer aggregation, arguing that it would be "very difficult, if not impossible" to conduct a competitive bid process that compares a PPA or owned generation with the "traditional" standard offer service.

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Oncor Clarifies Fees for Prepaid Services Using Advanced Meters

Only reconnection fees for prepaid customers using Oncor's advanced meters will be set at zero, Oncor clarified during a workshop on prepaid service using advanced meters, consistent with PUCT Subst. R. §25.498 (36233).

Some market participants were under the incorrect impression that fees for other prepaid services using advanced meters, such as disconnects for non-pay, would also be set at zero, but that is not the case. Only reconnects after disconnects for non-pay for prepaid customers using advanced meters will be set at zero dollars, Oncor said.

The settlement in Oncor's advanced metering deployment case requires Oncor to support prepaid functionality using advanced meters by June 1, 2009. Oncor has developed an interim solution to accommodate such prepaid service by that deadline, prior to the full deployment and backoffice development of the advanced metering system.

Under Oncor's proposal, REPs must notify Oncor of their prepaid customers. Oncor will then be able to reconnect such prepaid customers with advanced meters within one hour of receiving a reconnect notice from the REP. That gives REPs one hour to send their reconnect transaction to Oncor after receiving customer payment, as PUCT rules require reconnection within two hours of payment for prepaid customers.

Oncor's interim solution is designed to minimize system changes, does not require a new EDI transaction, and can be implemented independent of a Texas SET release. REPs would use Priority

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UI Reports December Shopping Data

United Illuminating Switching Statistics As of December 31, 2008

Total Accounts with Alternate Supplier: 36,285

Customer Count Breakdown:

3rd Party Supplier	Residential	C&I	Total	November 30, 2008 Total
Clearview Electric	0	0	0	0
Consolidated Edison Solutions	961	838	1,799	1,724
Constellation NewEnergy	111	2,838	2,949	3,316
Direct Energy Services	5,300	1,104	6,404	4,767
Dominion Retail	15,839	1,086	16,925	17,027
Gexa Energy	0	57	57	49
Glacial Energy of New England	26	352	378	380
Hess Corporation	0	55	55	57
Integrys Energy Services	3	1,639	1,642	1,571
Liberty Power Delaware	0	23	23	23
MXenergy	1,305	998	2,303	2,395
Public Power & Utility	1,739	380	2,119	1,922
Sempra Energy Solutions	29	448	477	474
Strategic Energy	10	588	598	665
Suez Energy Resources NA	0	96	96	49
TransCanada	8	452	460	461
Totals	25,331	10,954	36,285	34,880

		% of Class Shopping
UI Last Resort Service (LRS)		
Total # All LRS Accts	294	
Total All LRS MWhs	127,747	
Total 3rd Party LRS Accts	267	91%
Total 3rd Party LRS MWhs	120,367	94%
UI C&I Standard Service		
Total # All C&I SS Accts	38,135	
Total All C&I SS MWhs	167,380	
Total 3rd Party C&I SS Accts	10,687	28%
Total 3rd Party C&I SS MWhs	85,916	51%
UI Residential Standard Service		
Total # All SS Res. Accts	290,198	
Total All SS Res. MWhs	213,826	
Total 3rd Party SS Res. Accts	25,331	9%
Total 3rd Party SS Res. MWhs	21,088	10%
Total All UI		
Total # ALL Accts	328,627	
Total ALL MWhs	508,953	

Reflects data as reported by UI.

Mitigation Measures Lead to Sharp Decline in Unsold ICAP Supplies

New market mitigation measures for the New York ISO ICAP market, which took effect last summer, have resulted in a sharp decline in the amount of capacity that was not sold, as a percent of capacity offered, NYISO said in a report to FERC (ER03-637)

Capacity not sold as a percent of capacity offered was 9% for the winter 2006-07 capability period, but fell to 0.63% for the winter 2008-09 capability period, with no level of unsold capacity for the summer of 2008.

The new mitigation measures require pivotal suppliers to offer their capacity at the demand curve default reference price. The requirement eliminated the effects of the behavior of one in-City supplier that always offered its capacity at the previously implemented price caps associated with prior mitigation measures, NYISO said.

While NYISO found that the overwhelming share of capacity that is not offered is withheld for "benign" purposes, as opposed to strategic motives, it did note market participants continue to report one-time occurrences that raise participants' concerns. However, NYISO found that the small amounts withheld were due to various legitimate factors, such as retirements, environmental restrictions, gas pipeline issues, or precautionary purposes.

Although an average of 62 MW was offered but not sold in the Rest of State (ROS) summer 2008 capability period (0.17% of the minimum capacity requirement), NYISO's analysis did not find withholding concerns, given that suppliers were not pivotal, and that the average market clearing price was less than one-third of the Net Cost of New Entry.

"Any regulatory intervention in the bidding freedom of ROS ICAP suppliers would not be justified by the market's structure or performance, and would be inconsistent with the Commission's policy and precedent," NYISO said.

NYISO also reported that, though a causal relationship is difficult to determine, increased interconnection activity may be attributed to higher ICAP curves for the 2008-10 period. The current ICAP market structure provides sufficient market signals to anticipate future revenues, NYISO contended, though it continues to evaluate with stakeholders a forward capacity market to make these signals even more apparent.

Demand response providers not affiliated with transmission owners, including LSEs not affiliated with utilities, currently sponsor 71% of Emergency Demand Response Program and Installed Capacity-Special Case Resource Program megawatts in the New York ISO as of August 2008, up from 62% a year ago, NYISO reported. Among 42 curtailment service providers are seven transmission owners, four LSEs not affiliated with transmission owners, 24 aggregators, and seven direct customers.

DPUC Asks for Comments on Utility-Supplier Billing Rules

The Connecticut DPUC invited comments from stakeholders regarding its review of Conn. Agencies Regs. §16-245d-1 et. seq., which govern the components and information that must be contained in all bills issued to customers by electric distribution companies, and the billing relationship between electric distribution companies and competitive suppliers (09-01-07, Matters, 1/12/09).

The Department opened an investigation of the current rules after it became apparent in its review of billing errors at Connecticut Light and Power that CL&P does not consistently provide accurate customer data to competitive suppliers in a timely manner, and therefore, suppliers cannot bill customers accurately or timely. Furthermore, CL&P's policy is not to provide estimated usage data for accounts in Classes 30 and higher, so competitive suppliers are left with absolutely no data with which to bill customers when CL&P fails to provide actual data,

While market participants are encouraged to comment on any or all subject areas addressed by the regulations, the Department specifically requested comments on the following question: What, if anything, should be required of electric distribution companies that is not already addressed in the current regulations, to make suppliers' billing of customers more efficient or more beneficial to customers (for example, should the electric distribution companies be required to provide estimates for all rate classes, and should they also be required to transfer billing data to the suppliers no later than 3 days after meter reads)?

Comments are due February 20.

While the DPUC recognizes the problems associated with not getting accurate meter reads, it also said, in a letter to TransCanada Power Marketing, that the Department has not placed importance on when bills are issued to customers, but only that bills are issued on a regular schedule. In a compliance filing regarding payment plans offered to customers with incorrect bills due to CL&P errors, TransCanada had observed that the general standard throughout New England is for the utility to provide the metered usage to competitive suppliers within five business days of the meter read. If a usage transaction arrives more than seven days after the meter read, then the supplier would have to issue an estimated bill to send a bill to customer within 10 days, TransCanada said. However, the DPUC noted that it has not required competitive suppliers to issue their bills within ten days of a utility bill.

Although some customers might place considerable importance on receiving their supplier invoice close in time with their utility invoice, it is more important that customers receive all bills on a regular and known schedule, the DPUC said. Thus, for instance, if a utility issues a customer bill on Day 1 and typically provides such customer usage data to the supplier on Day 5, and the supplier needs five days to create its own bill, then the supplier should designate Day 10 as the regular schedule for that customer bill. Under such scenario, the bill would not be considered a "missed bill" or "an accurate bill of zero dollars" until Day 20, the DPUC explained.

Briefly:

Dominion Retail Submits Conn. Customer Ops Plan

Dominion Retail submitted its operations and customer service plan in response to a Connecticut DPUC order regarding Dominion's operation in the Connecticut market, and use of aggregator Levco Tech (06-08-03, Matters, 12/4/08). Among other things, Dominion says that, if it uses a third party including an aggregator to solicit customers, the third-party will clearly disclose that it is marketing on behalf of Dominion. Customers will also receive a Dominion-branded disclosure label and standard terms and conditions, even when solicited by third parties. The DPUC had objected to the fact that Dominion, in using Levco Tech, had not been directly entering into a contract with residential customers aggregated by Levco. Rather, the only agreement that the customer signed was an agreement with Levco, which contained language that the customer agrees to switch from their current electric supplier to, "the electric supplier selected by Levco Tech, Inc."

Maine Co-ops ... *from 1*

Limiting the ability of a cooperative to use a PPA to serve the standard offer aggregation would inhibit new generation development, as PPAs are required to finance generation projects, Dirigo said.

Dirigo also recommended that a cooperative be allowed to implement a standard offer aggregation longer than five years without express approval from the PUC, so long as the cooperative's board approves the length of the term. Longer aggregations will be needed, Dirigo said, to match the term lengths of PPAs that cooperatives may sign.

The PUC's draft rules would typically limit aggregations to five years, though the PUC could grant an exception where justified, such as for a PPA. The PUC's proposal set a general limit of five years for the aggregations so customers can periodically consider service from the competitive market.

All standard offer aggregations from cooperatives would require approval by vote of the co-op's governing board due to, "the potential significant impact on customers," the PUC said in discussing its draft.

Under the Commission's proposal, cooperative customers may opt-out of the aggregation service by providing notice to the co-op at least 30 days prior to the initiation of service. The 30-day notice requirement is intended to balance the interests of customers in being able to consider current market circumstances, and the interests of suppliers in load certainty prior to committing to supply or supply hedges.

However, there is no requirement that the co-op provide notice of the actual load aggregation prices in advance. Co-ops must only provide notice of the aggregation between 120 and 90 days from the start, while disclosing non-price terms and conditions, including start and end dates.

Furthermore, cooperative customers not opting out of the aggregation can be required to remain on the standard offer for a pre-specified term. "[T]his ability to limit migration is at the core of the [co-op's] proposal to aggregate load pursuant to the Act," the PUC noted, and is meant to lower migration risk in standard offer prices.

A "prominent" statement in the aggregation notice must inform customers that if they do not opt-out of the load aggregation, they will be required to continue to take service from the load aggregation throughout its term.

The PUC's draft would require co-ops to serve existing customers seeking to be served under the standard offer aggregation after its start, but holds such customers may be charged a different price than the standard offer. New load from medium and large non-residential customers, and load expansions above a pre-specified level, that initiates service after an aggregation offer's start date may also be charged an alternate price, the draft says. "This provision would reduce the supplier's risk of unexpected significant new load that should result in lower standard offer prices," the PUC said.

Customers with pre-existing competitive supply contracts may take service at aggregation prices at the time the competitive contract terminates, if notice is provided to the co-op at least 30 days prior to the initiation of load aggregation service. Otherwise, alternate rates, such as market-based rates, may apply.

The PUC's proposed rules also clarify that co-ops may consolidate their loads for purposes of standard offer load aggregation.

Since the PUC opened the co-op load aggregation rulemaking, which would revise the standard offer rules, the Commission opted to propose changes to the current security and credit provisions of the standard offer rules as well, given the current financial and credit market conditions. The Commission's draft would add language to the standard offer rule specifying that the PUC has the flexibility to determine whether corporate guarantees will be an acceptable means to satisfy the standard offer's financial security requirements.

Oncor ... *from 1*

Code 5 in the 650 Transaction to identify prepaid customers with an advanced meter. REPs will be able to determine if their customers have an advanced meter through Oncor's monthly ESI ID reports. REPs would send a list of their prepaid customers' ESI IDs as a backup for Oncor to use if communications with the advanced meters experience problems.

The process would work in the following manner. A REP would send a Disconnect for Non-Pay (650-01) transaction to Oncor to disconnect a prepaid customer. Oncor would complete the disconnect using the advanced meter. When the customer pays the REP to be reconnected, the REP would send a Reconnect Transaction with Priority Code 5 to Oncor. Oncor would confirm the premises has an advanced meter, and, upon confirmation, would reconnect the customer within one hour of receiving notice from the REP.

However, if the customer does not have a provisioned advanced meter, Oncor, under its original proposal, would reject the transaction. That caused discussion among other TDSPs and REPs, as they argued the customer should not be harmed (through a rejected transaction which may delay reconnection) simply because the REP submitted the incorrect transaction in sending an advanced meter reconnect rather than a standard reconnect. CenterPoint Energy suggested that, if the prepaid customer did not have an advanced meter but the REP submitted a reconnect for an advanced meter, it would process the transaction under the normal timeline, rather than rejecting the transaction.