Energy Choice Matters

May 14, 2009

Illinois A.G. Asks for Expanded Electric Consumer Protections by August 31

After criticizing earlier language regarding the definition of "power and energy services" to be included in purchased electric supplier receivables at the Ameren Illinois utilities as too broad, Illinois Attorney General Lisa Madigan opposed updated language agreed to by suppliers and Ameren as too specific, though Madigan agreed that competitive suppliers should be allowed to include the cost of RECs or other RPS compliance mechanisms in the purchased receivables (08-0619 et. al.).

Under an Memorandum of Understanding between Ameren and several suppliers (Matters, 4/30/09), the "power and energy services" receivables to be purchased by Ameren would include costs for services to meet a customer's instantaneous power and energy requirements, including transmission charges and costs of compliance with the renewable portfolio standards as set forth in Public Act 95-1027, and related codes.

The A.G. said that such a definition is "unnecessarily specific," and should not include reference to specific RPS laws or codes. Madigan proposed that purchased receivables instead be defined as including, "costs of compliance with any and all applicable renewable portfolio."

However, Madigan is still pushing for a requirement that suppliers express all power and energy services on a per kilowatt-hour charge basis. "The goal should be to have product names and prices that are clear and easily understood by consumers, and to ensure that consumers can compare electricity supply products on a kilowatt hour basis," the A.G. said in requesting a uniform pricing requirement.

Illinois Commerce Commission Staff had previously cautioned against such a uniform pricing

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Brattle Report Outlines Benefits, Risks from Maine Independent System Administrator

While a Maine Independent System Administrator (ISA) would be a "feasible alternative" to Maine's continued participation in ISO New England, and may produce lower energy and capacity prices in the short term, the ISA arrangement would likely increase transmission costs, increase the risk of market power, and hinder development of wind generation in the state, a report from the Brattle Group concluded (2008-156).

The Brattle report, prepared for Central Maine Power and the Industrial Energy Consumer Group at the request of lawmakers (Matters, 3/23/09), examined a Maine ISA that would essentially retain the Northern Maine ISA's framework with respect to its governance, regulatory compliance, transmission service, and reliability coordination, and that would build on the New Brunswick System Operator's (NBSO) market design with respect to providing imbalance energy and ancillary services in the Bangor Hydro-Electric and Central Maine Power portions of the state.

Under the studied scenario, NBSO would perform control area functions for all of Maine as the balancing authority and reliability coordinator, including generation dispatch, regulation, system reliability, and managing interchange schedules with neighboring balancing authorities, which include ISO-NE, Hydro Quebec, and Nova Scotia.

The Maine ISA would provide a "day 1" (i.e., a non-market, non-RTO based) type of transmission

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Conn. Customers Join Retailers in Opposing Re-regulation

Connecticut residential customers choosing a competitive electric supplier can save up to $17/month while commercial customers can save up to $50/month versus default service, a coalition of retail suppliers, business leaders and legislators said yesterday in opposing legislation which would prohibit retail choice for customers under 100 kW (Matters, 4/30/09).

"More so than at any time since the market was restructured, consumers and businesses are finding value in the market and exercising their right to buy electricity at better prices and with more options than were available before," said Jay Kooper, Retail Energy Supply Association President, during a capitol news conference.

Kooper noted that the current number of Connecticut shoppers, some 148,000 customers, exceeds the population of Connecticut's largest city, Bridgeport. Kooper presented over 800 emails and 3,800 postcards from customers asking that choice be preserved.

"It's very clear that residential customers in this state want their choice of electricity just like any other commodity," Kooper said.

Kevin Maloney, who runs Windsor Locks-based Northeast Express Transportation, said his business is saving $1,200 annually from electric choice. Maloney complained about the lack of transparency from proponents of ending choice, noting the proposal was tacked onto an unrelated bill. Ending choice would be a "mistake," Maloney said, adding that very few customers know about their options to save money, and that a better job needs to be done to get the word out.

"Many competitive suppliers are offering prices well below the utility prices today," added David Pearsall, president of Connecticut-based Public Power and Utility. "Competition is delivering lower prices and putting money in the pockets of Connecticut consumers when they need it the most," Pearsall noted.

"These are difficult times and ending retail choice would deprive many of our members of the ability to choose a lower priced service from competitors just at a time when they need those savings most," added Andy Markowski, Connecticut coordinator for the National Federation of Independent Business (NFIB).

Richard Laurenzi, President of Prospect Machine Products, also urged lawmakers to preserve choice, arguing that the 100 kW cutoff is arbitrary and unjustified.

Democratic Sen. John Fonfara, co-chair of the joint Energy & Technology Committee, said the bill amounts to a rate increase for thousands of customers. Though Fonfara would not handicap the bill's future, he said he would make his opposition clear, and would not speculate as to whether it would even be discussed in caucus, let alone reach the floor. Fonfara, who holds considerable sway as Deputy Majority Leader, pointed to the substantial growth in customer migration since market-based rates began in 2007, adding that retail choice is needed to bring smart grid innovations, such an in-home monitors and smart appliances, to Connecticut.

ComEd Applies to Accelerate Recovery of Stabilization Charges

Commonwealth Edison applied at the Illinois Commerce Commission to accelerate its collection of deferrals under the residential rate stabilization program, which has provided for an extended transition from capped rates to market-based supply rates.

Initially, recovery of deferrals from 2007, 2008 and 2009 was to begin in 2010 over a three-year period.

Due to the lower retail rates starting June 1 (the result of favorable pricing in a recent procurement), the currently designed rate stabilization program would actually apply a ¢/kWh charge, not a credit, to customer bills starting in June, which would be used to begin paying off the deferrals. However, due to expectations at the time of the program's development, based on forward wholesale prices, ComEd did not include programming code in its billing system to effect such a variable ¢/kWh charge in mid-stream, as the likelihood of the stabilization mechanism producing a surcharge rather than a credit was thought to be low.

Instead, programming code was put in place in the billing system to implement a stabilization adjustment at the end of the deferral period, as a fixed (not volume based) monthly charge individually determined and applied for each active participant over a 36 month period that was to begin with the January 2010 monthly billing period.

Accordingly, ComEd asked to move forward the 36-month repayment period via the fixed surcharge to June 2009, which will not generally increase the total amounts paid by customers, and will provide a slight benefit for some 19,000 of the 26,000 deferral program participants (less than $2 in total savings from lower interest payments). ComEd believes that accelerating the fixed-charge, 36-month payback period will be less confusing to customers than using a variable, ¢/kWh charge for the rest of 2009, and then moving to the fixed charge as scheduled in 2010.

Ontario Energy Board Revises TOU Periods

The Ontario Energy Board issued revised periods applicable to Time of Use (TOU) rates under the Regulated Price Plan, to take effect this fall (EB-2007-0672).

The Board concurred with stakeholders that the seasonal variations and the three-price structure in TOU rates should continue, but said simplifications are required. In particular, OEB said that the winter evening period is too fragmented, with a two-hour mid-peak period (from 8 p.m. to 10 p.m.) occurring between on-peak (from 5 p.m. to 8 p.m.) and off-peak (from 10 p.m. to 7 a.m.) periods.

To simplify rates, the Board eliminated the winter evening mid-peak period, starting November 1, 2009, by extending the on-peak period by an hour, and accelerating the start of off-peak prices. A morning mid-peak period will be retained. The new winter TOU rates will be as follows:

Winter Weekdays (Nov. 1 - April 30)

7:00 a.m. to 11:00 a.m.	On-peak
11:00 a.m. to 5:00 p.m.	Mid-peak
5:00 p.m. to 9:00 p.m.	On-peak
9:00 p.m. to 7:00 a.m.	Off-peak

The Board is also changing the start of off-peak prices in the summer evenings from 10 p.m. to 9 p.m., resulting in evening off-peak prices beginning at 9 p.m. year round. Summer TOU periods will now be:

Summer Weekdays (May 1 - Oct. 31)

7:00 a.m. to 11:00 a.m.	Mid-peak
11:00 a.m. to 5:00 p.m.	On-peak
5:00 p.m. to 9:00 p.m.	Mid-peak
9 p.m. to 7:00 a.m.	Off-peak

OEB also noted that while it established a target TOU price ratio of 1:2:3 (off-peak:mid-peak:on-peak) to encourage load switching, the application of Global Adjustment costs has narrowed the difference between off-peak and on-peak rates. The Global Adjustment is a reconciliation between the total payments made to certain contracted generation and demand resources, and retail revenues. OEB noted that the adjustments will become a larger proportion of total Regulated Price Plan supply costs going forward.

The current method of supply cost recovery allocates Global Adjustment costs uniformly on a per kilowatt-hour basis across all TOU supply, meaning that off-peak TOU prices increase proportionally more than on-peak prices, resulting in the narrowed gap between TOU rates.

To resolve this problem, the Board will allocate Global Adjustment costs that can be attributed to peak energy supplies or load reduction initiatives to on-peak prices. Global Adjustment costs attributable to baseload supplies will be recovered through all three TOU prices. The new allocation, to start with the November 1 regulated prices, will preserve load shifting incentives in TOU prices while maintaining supply cost recovery, OEB said.

Weyers Talks Up Value of Integrys Energy Services

Integrys Energy Services' rapid growth makes it an "attractive business," but the competitive provider requires a parent, "with a much larger balance sheet, particularly in today's illiquid financial environment," Integrys Energy Group Executive Chairman Larry Weyers said at an annual shareholders meeting.

Although Integrys intends to divest or otherwise wind down the Energy Services unit, Weyers maintained that the competitive unit had its best year ever creating value in 2008, though the unrealized impacts from hedging did not reflect the success in GAAP numbers.

Despite the success, the unit requires substantial credit facilities to support its operating model -- credit that can be supplied by a parent company with a large balance sheet or more liquid financial markets, Weyers said.

Weyers reiterated Integrys' recent statement that it will likely announce an update on divestiture plans in the late third quarter or fourth quarter of this year.

ERCOT Reports on RPS Opt-Outs, Compliance

There are currently ninety-three ESI IDs opting out of the Texas RPS program, ERCOT said in a report on the REC program. Transmission-level voltage customers received the ability to opt-out in 2007.

ERCOT also reported that the only REPs which failed to comply with their 2008 RPS requirements were REPs that exited the market in 2008, including Juice Energy (5% out of compliance), National Power Company (100%), Pre-Buy Electric (100%) and W Power & Light (73%).

ERCOT's report, posted in PUCT project 27706, also lists the 2007 REC requirements and voluntary REC retirements of each individual REP, as the confidentiality of such information has expired.

As previously reported, total RECs retired for compliance with the 2008 RPS mandate were 6.74 million, surpassed for the first time by voluntary REC retirements for optional green products, which totaled 6.77 million (Matters, 4/2/09). Total renewable generation was 17 million MWh in 2008, up from 10 million MWh in 2007.

Briefly:

Direct Reports Lower Texas Margins Offset by Northeast, Canadian Growth

Conditions remain "challenging" in North America, Centrica said in an interim investor update, as Direct Energy is seeing lower margins in its Texas retail business in the first quarter due to higher-priced forward-purchased commodity. However, the Texas results have been offset by improved profitability in Direct's Canadian and U.S. North mass market business and in its commercial and industrial business, in which Direct said it is now seeing the post-integration upside from the acquisition of Strategic Energy in 2008. Low wholesale energy prices are reducing profitability in Direct's upstream and wholesaling business, and there are also no signs yet of any improvement in the new home construction market which has slowed Direct's home services unit, Centrica said.

Illinois Wind RECs for ComEd Average $21

The average winning price for Illinois-sited wind RECs from a May 11 Illinois Power Agency procurement for Commonwealth Edison load was $21.13/REC, the Illinois Commerce Commission said in approving the procurement results. Nearly 1.2 million Illinois wind RECs were procured. Additionally, 391,000 Illinois-sited, non-wind RECs were procured at an average winning price of $13.69/REC. The IPA did not procure any RECs from other states. Winning suppliers included Ameren Energy Marketing, Beecher Energy, CE2 Environmental Opportunities, City of Peru Electric Department, Conectiv Energy Supply, Constellation Energy Commodities Group, EcoGrove Wind, Element Markets, Exelon Generation, Iberdrola Renewables, Integrys Energy Services, Invenergy Renewables, Nexant, NextEra Energy Power Marketing, PSEG Energy Resources & Trade, Rail Splitter Wind Farm, Sterling Planet, and WM Renewable Energy.

DPUC Approves CL&P Standard Service RFP

The Connecticut DPUC approved Connecticut Light and Power's May 12 procurement of Standard Service supplies for portions of 2009, 2010, 2011, and 2012. Standard Service retail prices for the period beginning July 1 must be posted by May 19.

Summitt Energy Management Seeks New Ontario Trade Name

Summitt Energy Management has applied at the Ontario Energy Board to add the trade name My Rate Energy to its electric and gas licenses.

Integrys Energy Services Cannot Wait Much Longer Before Seeking SECA Writ

Supporting recent comments from AMP-Ohio, Integrys Energy Services urged FERC for a decision on Seams Elimination Cost Adjustment (SECA) charges imposed on LSEs operating in PJM and the Midwest ISO, informing the Commission that it cannot wait much longer before returning to a U.S. Court of Appeals for a second writ of mandamus to resolve the case (ER05-6 et. al., Matters, 5/11/09). Integrys Energy Services agreed that further settlements are unlikely, calling the entire SECA proceeding a "travesty" for retail suppliers.

PUCO Clarifies Waivers under SSO Rules

The Public Utilities Commission of Ohio further revised its new rules regarding the electric Standard Service Offer and related aspects of the competitive market, clarifying that the Commission cannot waive any requirement of the rules that is mandated by statute. A previous PUCO order had held the Commission could waive any of the rules for good cause shown. Affected are Ohio Administrative Code chapters 4901:1-35, 4901:1-36, 4901:1-37, and 4901:1-38, which establish the means of SSO service, various riders, and other electric market provisions.

PUCT to Review Intervention Deadline

The PUCT has opened project 36987 for a rulemaking to amend Procedural Rules §22.52(a), §22.75(d), and §22.104(b). Rule §22.104(b) sets the intervention deadline for contested cases, which is currently 45 days. The other two rules relate to regulated electric licensing proceedings (such as transmission).

FERC to Review Use of Frequency Response for Wind Integration Studies

FERC said it has commissioned a "groundbreaking" new study that will use Frequency Response to assess reliable integration of wind and other renewable energy resources. The Commission said the study, to be performed by Lawrence Berkeley National Laboratory, is the first time any analysis has examined using frequency response to objectively determine how much renewable energy can be reliably integrated into the bulk power system. The six-month study is to determine whether frequency response is an appropriate metric to assess the reliability impacts of integrating renewables, and the study will use the resulting metric to assess the reliability impact of various levels of renewables on the grid.

PG&E Signs Solar PPAs

Pacific Gas and Electric Company has entered into a series of PPAs with BrightSource Energy for 1,310 MW of solar thermal power.

Ameren POR ... *from 1*

requirement, noting it could hinder product differentiation and a la carte options such as those offered in the telecom industry. In its reply, the Citizens Utility Board argued that, "The comparison of electricity service to telephone service is of no use to the issue at hand, because there is simply no comparison between the myriad functionality and services currently available in the telecommunications marketplace and the singular ability to 'turn the lights on' in one's home."

However, the Illinois Competitive Energy Association and Retail Energy Supply Association called Madigan's proposed requirement that power and energy charges must be expressed on a per kilowatt-hour basis, "vague," noting the A.G. failed to provide any specifics on the proposal, how it would be implemented, or how it would provide any substantial benefit to anyone. RESA and ICEA also pointed to the various consumer protection standards in place under the Illinois Administrative Code, and the Illinois Consumer Fraud Act and Deceptive Business Practices Act.

But Madigan said such regulations, "fail to address a common use of terms such as 'fixed bill' or 'fixed price' in describing [competitive] products."

"For that reason, it is necessary to move beyond existing rules to ensure that confusion and unnecessary delays [in market development] are avoided," the A.G. said.

While the Office of Retail Market Development is working on comprehensive customer protection rules, the A.G. requested that the ICC order that consumer protection and education requirements be developed by August 31, 2009. Such protections must address the issues identified in POR proceeding, such as uniform pricing, a Commission-run electric choice website, procedures for maintaining a "do not contact" list, and contents of a universal product disclosure form, Madigan said.

ICEA and RESA said that any additional consumer protections should only apply to residential customers and non-residential customers consuming no more than 15,000 kWhs annually.

Maine ISA ... *from 1*

service compatible with FERC Order 888's pro forma tariffs for network service, firm point-to-point service, and non-firm point-to-point service.

The Maine ISA's market functions would be structured based on the NMISA-NBSO market design to support a bilateral market model (a day-1 market) rather than the security-constrained, locational-pricing and congestion-management-based market model available within ISO-NE (a "day 2" market).

Such an arrangement, Brattle said, would include several advantages over the status quo. Among them is a likely reduction in energy and capacity costs under the Maine ISA model, at least in the short-term, as higher transaction costs for exports would result in more in-state generation being offered in Maine. However, any reduction in energy prices could be short-lived due to increased generation retirements and less generation investment, particularly from lower levels of renewable generation investments, due to the isolated nature of the ISA market, Brattle noted.

Capacity costs would likely be lower in the long-term as well as the short-term, Brattle said, due to the long-term excess capacity for the region.

Prices would likely be more stable due to long-term contracts and less reliance on short-term purchases, Brattle said. Under the ISA model, Maine would be less dominated by volatile gas generation resources, Brattle added. Maine would also save on ISO-NE administrative costs, though savings would not likely amount to more than 0.25% of current retail rates for residential customers.

Maine would likely have a larger voice on its energy future under the ISA model, including with respect to transmission planning and transmission cost allocations. While Maine's operating reserves obligation would increase, the costs may decrease due to lower reserves prices, Brattle said.

However, Brattle noted that implementation of a Maine ISA would also expose Maine ratepayers to several risks and, from a total retail electricity rate perspective, may not yield significant savings. A more detailed cost and benefit analysis is required to determine the magnitude of any long-term savings, Brattle said.

To begin, the Maine ISA option may not lead to lower transmission costs given the significant cost of planned transmission investments in Maine. Unless approximately 45% of the combined BHE-CMP transmission costs - including the Maine Power Reliability Project cost - could be allocated to ISO-NE and others under the Maine ISA alternative, customers in the Rest of Maine service area would pay higher transmission charges under the Maine ISA option than under continued ISO-NE participation. It's not clear if such costs could be passed onto ISO-NE customers through wheeling-out charges or pancaked rates.

Furthermore, the creation of seams between Maine and ISO-NE could reduce generation development, including wind power development, and create market inefficiencies that can be expected to partially or fully offset any short-term reductions in energy and capacity prices, Brattle said.

The ISA's day-1 market design would impose additional transaction costs on generators in Maine, particularly for wind generators for whom reserving and scheduling transmission would be more challenging and more expensive due to the variable nature of wind generation.

The combined peak load for Maine and New Brunswick is only about 5,200 MW, Brattle noted, which means it may be difficult integrate more than 1,000 MW of wind resources (20% of load) in the combined Maine-New Brunswick footprint.

The new market structure would likely reduce price transparency and diminish the effectiveness and attractiveness of price-based demand-response programs, Brattle added.

In contrast to the ISA proposal, the pricing transparency offered by day-2 markets is important for a retail competition environment, Brattle observed. Other than in Northern Maine, Brattle is unaware of any other U.S. market with active retail competition operating in a day-1 wholesale market environment. The absence of an hourly day-head and a real-time energy market in the current NBSO design would also make it more difficult to procure hourly blocks of energy needed to match supplies to hourly changes in load.

Neither NMISA nor the NBSO currently has formal and active market monitoring and market power mitigation processes to guard against the exercise of market power in energy and ancillary service markets. To reduce the risk of market power abuse - including by Canadian suppliers who "dominate" their home markets - market monitoring and mitigation functions would need to be created to ensure workably competitive wholesale markets that can support retail competition under the ISA model. Brattle noted the New Brunswick market is dominated by NB Power, which owns close to 4,000 MW of generating capacity or about 85% of all New Brunswick generation resources. NB Power also controls approximately 700 MW of the 1,000 MW of transmission capability between New Brunswick and Maine, with Hydro Quebec (also dominant in its home market) controlling the remainder.

Brattle also raised questions regarding whether the Maine ISA design would meet with FERC and New Brunswick provincial approval.