Energy Choice Matters

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Illinois Staff Open to Long-Term SOS Supply Contracts, But Opposes Hasty IPA Plan

The hedge value of entering into long-term default service supply contracts with fixed prices applies equally to coal, nuclear, and natural gas plants in addition to renewable resources, Illinois Commerce Commission Staff said in commenting on an Illinois Power Agency proposal to include a solicitation for long-term renewable PPAs in the next procurement (Only in Matters, 10/2/09). Staff objected to including any long-term PPAs in the 2010 plan because a host of issues have not been addressed in the IPA's late recommendation for the PPAs, but Staff said future long-term supply contracts should be explored under a robust analysis comparing various options.

As only reported by *Matters*, the IPA, in a revision from its earlier draft plan, proposed to procure long-term renewable PPAs in the amount of 1,400,000 MWh annually at Commonwealth Edison, and 600,000 MWh at Ameren.

"Staff is not, in principle, opposed to long-run PPAs with renewable or conventional power producers," Staff said. However, Staff argued that the IPA's proposal lacks justification and fails to address many important issues. "Furthermore, these deficiencies are unlikely to be rectified in the time available for this proceeding ... It is noteworthy that the IPA's draft plan, provided to the parties on August 17, 2009, included no such [long-term PPA] proposal," Staff said. The final plan filed by the IPA on September 16, after receiving comments favoring bundled long-term PPAs from the Attorney General, renewable developers and others, included the long-term PPA proposal for the first time.

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Revised D.C. NOPR Would Allow Retailers to Negotiate Rate for Excess Customer Generation

Competitive electric suppliers would be allowed to negotiate the rate paid to customers providing the supplier with excess distributed generation, under a revised NOPR released by the District of Columbia PSC (FC 945)

As only reported by *Matters*, an earlier NOPR did not include any specific language governing net metering provided by competitive suppliers (Only in Matters, 4/2/09). Rather, all excess generation (for systems in excess of 100 kW) was to be paid the "the kilowatt-hour usage charge associated with the SOS generation service that is applicable to the customer-generator."

The revised NOPR creates a new section detailing the relationship between customer-generators and competitive suppliers. Under the proposed rules, suppliers are not compelled to provide net metering services, but may choose to do so. If they choose to offer net metering, "the net inflow or outflow of electricity supplied to or by the customer-generator will be billed or credited at the Competitive Electricity Supplier's energy rate specified in the agreement between the customer-generator and the Competitive Electricity Supplier."

The competitive supplier would be responsible for calculating the net energy bill (or credit) amount for each billing period.

Similar to bundled customers, customers on competitive supply with distributed generation of not

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Briefly:

Champion Energy Receives Ohio Electric License

The Public Utilities Commission of Ohio granted Champion Energy Services an electric supplier license to serve commercial, mercantile and industrial customers at the three FirstEnergy distribution companies (Only in Matters, 9/2/09).

PUCT Opens Rulemaking on Transmission Service Rates

The PUCT opened Project 37519 for a rulemaking to amend PUC Subst. R. §25.192(G), relating to transmission service rates. As only reported by *Matters*, the Commission adopted Staff's suggestion to open a comprehensive rulemaking on transmission cost recovery after several transmission service providers applied for authority to update the interim Transmission Cost of Service (TCOS) more frequently (Only in Matters, 8/27/09). REPs have cautioned that more frequent changes in the Transmission Cost Recovery Factor (which would likely follow more frequent changes to TCOS) could negatively affect retail suppliers, especially if updated Transmission Cost Recovery Factors are revised with little advance notice, preventing REPs from implementing billing changes to immediately pass through the new costs to customers.

O&R Files Updated POR Discount Rate

Orange and Rockland filed an updated electric Purchase of Receivables discount factor of 1.283%, effective November 1, 2009. The discount reflects a Risk Factor component of 0.072%, an uncollectibles component of 0.362%, and credit and collections component of 0.849%. O&R also filed updates to the uncollectibles component of the electric Merchant Function Charge, setting the uncollectible rate at 0.652% for residential customers and 0.114% for non-residential customers.

Midwest Utility Consultants Seeks Ohio License

Midwest Utility Consultants applied for an Ohio natural gas broker license to serve all classes of customers at Duke Energy Ohio. Midwest Utility Consultants focuses on bill auditing services in addition to procurement.

Utility Rate Analysts Seeks Pa. Electric License

Utility Rate Analysts applied for a Pennsylvania electric broker/marketer license to serve all sizes of non-residential customers at PPL and Met-Ed.

Energy Future Holdings Issues Exchange Offer to Reduce Debt by $2 Billion

Energy Future Holdings announced exchange offers and consent solicitations aimed at reducing its debt of over $40 billion by $2 billion, by issuing $4 billion of new debt with later maturities to replace $6 billion in current debt. EFH, parent of TXU Energy, has in excess of $20 billion in debt due in 2014.

NRG Completes Unwind of Merrill Lynch Sleeve

NRG Energy said it has completed the unwinding of the Merrill Lynch credit sleeve inherited in its acquisition of Reliant Energy, approximately one year earlier than originally planned. The termination removes the liens associated with the original Merrill Lynch Credit Sleeve Amendment and brings the Reliant retail entities into NRG's corporate collateral package. In connection with the transaction, NRG posted approximately $435 million of cash to Merrill Lynch and Reliant Energy's counterparties, while Merrill Lynch has released liens on approximately $300 million of unrestricted cash as well as $250 million of previously posted cash Reliant generated since the May 1, 2009 acquisition by NRG. "By unwinding the credit sleeve early, Reliant's substantial cash flow can be used at the corporate level in the Company's overall capital allocation plans," said Robert Flexon, NRG's Chief Financial Officer, citing portfolio hedging efficiencies as well operational and cost improvements that are now possible with the unwinding.

Canadian Hydro Agrees to TransAlta Acquisition

With TransAlta Corp. sweetening its offer, Canadian Hydro Developers Inc. agreed to be taken over by TransAlta in a transaction worth Canadian $755 million, up from an original offer of Canadian $654 million. The combined company will have a generation fleet of 8,657 MW, including 1,900 MW of renewable resources. Some 543 MW of capacity is under construction and about 500 MW is in advanced development.

World Energy Solutions Brokers Rhode Island Gas Requirements

World Energy Solutions said it procured over 5 million Dth of natural gas for the State of Rhode Island on its online exchange. According to World Energy, the 36-month contract, which starts November 1, 2009, is projected to deliver over $1 million in budget savings to the state.

APX Applies for Ohio Certification of REC Tracking System

APX, Inc. applied at the Public Utilities Commission of Ohio for approval of APX's North American Renewables Registry as a qualified tracking system for renewable energy credits that electric utilities and competitive electric suppliers may use to comply with Ohio's Alternative Energy Portfolio Standard.

Maine & Maritimes Says Company is Not for Sale

Maine & Maritimes, parent of Maine Public Service, denied rumors that the corporation is currently for sale. Rumors surfaced after Maine & Maritimes contracted KeyBanc Capital Markets to explore strategic alternatives, but Maine & Maritimes said that, "The company has not made a decision to pursue any specific transaction or other strategic alternative, and there can be no assurance that this process will result in any specific transaction or other strategic alternative."

ConEdison Solutions Warns Customers of PPL Rate Cap Expiration

ConEdison Solutions yesterday issued a press release concerning the expiration of PPL rate caps and encouraging business customers to avoid expected rate hikes of 19-37% by switching to a competitive supplier.

ICC Staff Says Changes Needed to Peoples, North Shore Storage Policies

Illinois Commerce Commission Staff agree that changes are needed in the storage policies of North Shore Gas and Peoples Gas as applied to competitive retail suppliers, recommending several revisions offered by retailers in testimony during the LDCs' rate cases (Only in Matters, 6/12/09).

As only reported in *Matters*, Dominion Retail, Interstate Gas Supply, and Nicor Advanced Energy have argued that unequal storage treatment between the LDCs and suppliers artificially inflates the cost of gas charged by suppliers, who blamed the discriminatory policies for the 3% migration rate at the LDCs.

The three suppliers noted that although customers in the Choices for You (CFY) program pay the same amount for storage assets as sales customers, the daily and monthly injection and withdrawal restrictions the LDCs impose on competitive customers results in suppliers being able to satisfy only 71% of their peak day demands with LDC owned assets, whereas sales customers can satisfy 93% of their peak day demands with those assets.

The unequal treatment is the result of the LDCs' rules, which provide that the amount of storage capacity withdrawn from and injected into storage on a daily and monthly basis by each retail supplier is a fixed number that is administratively determined by the LDCs with a limited consideration of actual weather. With little injection or withdrawal flexibility, retail suppliers have limited ability to hedge daily price volatility, provide seasonal hedging, and meet day-to-day fluctuations in demand. "This lack of flexibility and need for additional pipeline capacity to meet peak demands artificially inflates the cost of gas provided by CFY suppliers and creates an uneven playing field for CFY suppliers seeking to compete with the Companies' regulated sales service," suppliers noted.

Staff agreed that changes are required, and recommended that the daily withdrawal and injection capability should be revised in accordance with suppliers' testimony. Suppliers had recommended that retailers be given daily injection and withdrawal rights that are commensurate with the rights and flexibility provided by the assets allocated to CFY customers through various charges.

Staff further supported monthly targets for injections and withdrawals based on a method commensurate with the LDCs' operations, again adopting the suppliers' recommendation.

Additionally, Staff said that the LDCs should provide suppliers with daily delivery targets based on the LDCs' best estimate of the customer's daily usage with a daily tolerance of ±10%.

Staff also supports suppliers' recommendation that retailers should be allowed to serve customers in arrears under the Single Billing Option (supplier consolidated billing), a capability which is particularly needed in order to serve budget billing customers who switch to competitive supply (since the reconciliation at end of budget billing with the utility creates a debit and puts the customer in arrears).

Staff believes that suppliers should have the option of keeping customers who are in arrears on the Single Billing Option if suppliers are willing to shoulder that risk. Since the LDC charges are paid first, suppliers have just as much of an incentive to collect as the LDC would, Staff noted.

However, Staff opposed suppliers' request, for customers migrating to competitive supply under the Single Billing Option with a credit due from the LDC, that the credit should automatically be transferred to the supplier to be applied to the customer's bill. Staff said such a requirement would be burdensome for the LDC, and added that the LDC has no way to verify a supplier's claim that the customer has agreed to transfer the credit to the supplier.

Customers should be allowed to take service from a retail supplier at service initiation, Staff agreed, noting that the rescission period only applies to a customer "switch." Furthermore, Staff concurred with suppliers that the LDCs' proposed 19-day rescission period is arbitrary and does not comply with the 10-business day requirement under statute. Staff said that the tariff language should reflect the 10-business day language in the law, which, due to holidays around Thanksgiving, may in limited circumstances equate to 19 calendar days.

The LDCs, Staff said, should be required to print additional information on supplier bills, including inventory volume and storage capacity volume in addition to deposit balance and carry forward volume. While the information is already available on the PEGASys system, Staff agreed that there is not a significant administrative burden to provide the information as requested.

Staff opposed suppliers' request to allocate administrative expenses related to choice to all customers through distribution rates, as proposed by suppliers. Currently, such charges are recovered from suppliers in the Aggregation Charge as well as through an additional charge on suppliers electing utility consolidated billing. Staff agreed with the LDCs that the administrative costs are incremental and thus should be recovered from customers electing competitive supply. However, Staff said that the issue could be further addressed in a workshop.

AEP-Ohio Opposes Call for Refunds of IGCC Charges

Columbus Southern Power and Ohio Power called a request from industrial customers for refunds of amounts collected to support construction of a utility-owned Integrated Gasification Combined Cycle plant premature, stating that the fluid planning process may lead AEP to start construction of an IGCC plant prior to a June 28, 2011 deadline.

In June 2006, the Public Utilities Commission of Ohio approved AEP-Ohio's request to recover certain Phase I costs of an IGCC facility. However, if construction did not begin within five years, costs were to be refunded to customers. PUCO also said that the plant is a source of "distribution ancillary services," opening the door for potential cost recovery on a nonbypassable basis.

Industrial Energy Users-Ohio noted that in an integrated resource plan filed recently with Virginia regulators, AEP stated that for its entire eastern zone, including its two Ohio utilities, it does not plan on constructing an Ohio IGCC facility in the next 15 years. In fact, the IRP indicates that AEP East is not contemplating any new baseload units in the forecast period, IEU-

Ohio noted. The IRP covers AEP's entire eastern footprint because the individual utility companies are planned and operated on an integrated basis.

As neither AEP-Ohio nor AEP East currently has plans to commence a continuous course of construction of the proposed IGCC facility prior to June 2011 in Ohio or any other location within the AEP East footprint, IEU-Ohio requested that PUCO direct AEP-Ohio to refund, with interest, the revenue it billed and collected for the IGCC facility. Since PUCO's prior order requires interest to be paid on such refunds, "it is in AEP-Ohio's and the public interest for the Commission to order a refund immediately instead of waiting until June 2011."

However, AEP-Ohio countered that the Virginia IRP merely represents a "snapshot" of the future, and said its plans may change to include construction of an IGCC facility before June 2011. As the circumstances affecting the resource plan are continuously changing, the IRP is not a commitment but only a plan at a specific point in time, AEP said.

"AEP Ohio believes that the Commission understood the uncertainty of the planning process when it provided the five-year window for commencing construction on the Great Bend IGCC on a continuous course," and said there is no reason to close the five-year window early.

Additionally, AEP said that, "[i]t is clear from the Commission's Entry on Rehearing that if and when the time comes to consider refunds, only the 'Phase I charges collected for expenditures associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest.' If IEU's position that an IGCC facility will not be built by AEP Ohio or any of its affiliates proves to be accurate, no refunds to customers would be forthcoming."

Md. OPC Backs Elkton's Requested RM 35 Waivers

The Maryland Office of People's Counsel supports Elkton Gas' request for a waiver of two provisions of new competitive gas market rules, finding that the costs are not reasonable given the lack of interest from competitors in marketing to Elkton's customers (Only in Matters, 9/15/09).

As only reported by *Matters*, Elkton is seeking a waiver of new rules requiring utility consolidated billing and first-of-the-month enrollments. Elkton said that utility consolidated billing would cost $376,000, or $60 per customer in its 6,250-customer service area.

"Requiring Elkton to configure its IT billing systems to provide for consolidated billing would be nonsensical in light of its experience to date," OPC said.

"The benefits of the change to Elkton's IT required to accommodate gas suppliers must also take into consideration the realities of the participation of gas suppliers to date in its market. Not having a single gas supplier enter the Elkton market for the past seven years argues that some characteristic of that customer base, its relative small size and potential for capture by an alternative supplier, cost of customer acquisition and geographical orientation may all play a role in any supplier's decision not to pursue customers in Elkton's territory," OPC added.

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"It would therefore appear that the IPA's proposal for long-term PPAs was quickly 'developed' in the span of two weeks. In Staff's view, this level of development is unacceptable for planning multi-billion dollar procurements," Staff argued.

Staff requested that the Commission, in rejecting the deficiently supported PPA proposal, provide guidance for future procurement plans on what analyses will be required to justify long-term contracts.

Among other things, Staff noted that expanding the resource types eligible for long-term contracts would provide, "more robust competition and a lower-price outcome for ratepayers."

If the IPA intends for its solicitation to be for unit-specific power (which is not clear), the IPA has failed to address issues from the more open-ended RFP process required to evaluate unit-specific offers, which will involve a more subjective and probably more time-intensive process, Staff added, citing several challenges with unit-specific, unit-contingent intermittent contracts.

"For example, a wind farm's output can be predicted with accuracy only when the forecast is made a few hours ahead of time," Staff noted. Citing production data from a southwest Minnesota wind farm, Staff noted that "[e]ntering into contracts only with this type of resource (for their expected average output) would result in an unpredictable hedge ratio ranging from 0.6 to 1.3 for January. The uncertainly associated with the supply just adds to the uncertainty associated with demand."

In contrast, "a fixed quantity hedge contract (like the ones that have been used in recent years by ComEd and Ameren), can be precisely specified at whatever level is desired," Staff observed. "[I]n a long-range plan, the level of output from a wind farm that can be expected over any given day or hour, months into the future, would be impossible to determine (except in very broad and uncertain terms). By way of contrast ... a fixed-quantity contract ... would be 100% predictable," Staff added.

Staff noted that the IPA's plan provides almost no details about the type of PPA contract envisioned by the IPA: "For example, will it be for fixed or variable quantities? If variable quantities, will it be the total output in any hour, a fixed percentage of the total output in any hour, or some other variable quantity specification? Will the energy be provided on a 'firm' basis or a 'unit contingent' basis. Will the sellers be responsible or liable for any failures to produce, deliver or sell any energy to the extent such failure is the result of scheduled outages, unscheduled outages, or other acts or omissions by the sellers?"

The plan further does not specify the length of the proposed long-term contracts. Nor does the plan specify the acceptable locations of the generating resources, Staff added.

While the IPA proposed procuring long-term PPAs in May 2010 for delivery "as early as" June 2011, Staff noted that it is not clear whether the solicitation is open to only new resources, or existing resources as well. While some types of resources could come online in the proposed timeframe, Staff said that the window has not been justified.

Also unclear is whether the IPA intends to use the long-term renewable contracts to achieve RPS goals, Staff said.

ComEd raised similar questions regarding the lack of specific details in the IPA's long-term PPA proposal, but said that, "ComEd believes that the parties should explore entering into long term contracts, including those for low carbon and renewable resources, as part of the procurement plan." Still, ComEd noted that long-term supply contracts would be a "dramatic change" that, "must be done with careful consideration of its impact on customers, the utility and other stakeholders."

ComEd's main objection was that if the PPAs are used to satisfy the RPS, the IPA has not addressed the cost caps placed on RPS compliance under statute.

ComEd further argued that while the IPA may contract for long-term energy under statute, the statute requires that such resources must be "standard wholesale products" and such contracts must be "standard contract forms."

"The reason this provision is in the law is to ensure that the IPA can select the lowest price bids by suppliers on a consistent basis without having to make difficult and potentially controversial evaluation assumptions to compare bids," ComEd noted. If the ICC approves a long-term contract procurement, it should require that any such procurement must be for standard wholesale products, be open to all market participants to ensure the lowest cost to customers, and require the use of the same standardized contract for all suppliers, ComEd said.

"Outside of the renewable provisions in the IPA Act, which are already being met, the [Public Utilities Act] does not permit special preferences for any group of suppliers," ComEd argued.

ComEd contended that standard product contracts provide the best hedge against potential future price increases driven by rising fuel and carbon related costs, because once the price is fixed the supplier, not the customer, bears all risks of cost increases.

Furthermore, "[b]efore any long-term contracts are executed, a detailed and comprehensive risk analysis must be conducted to ensure that such a contract will lower, rather than increase, costs and risks to customers," ComEd said, citing the potential for stranded costs.

Demand Response Procurement

Echoing earlier comments made by ComEd,

ICC Staff questioned why a separate demand response procurement as proposed by the IPA is needed at ComEd since the Reliability Pricing Model procures demand resources which clear the auction. Staff recommended that the ICC find that the RPM process already meets the statutory requirement to procure capacity in the form demand response whenever the cost is lower than procuring traditional capacity products.

At Ameren, where RPM does not apply, Staff questioned holding a fall demand response procurement (if no demand resource bids into the all-resource spring procurement), since a carve-out will not produce a head-to-head comparison of prices to allow the IPA to determine whether the demand resources are lower priced than comparable capacity.

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more than 100 kW would also receive credit for excess generation from Pepco paid at the full retail distribution rate. This payment would in no way reduce the amount of surplus kilowatt-hours to be credited by the competitive supplier at the generation rate.

Net energy billing would apply only to kilowatt-hour usage charges. Net energy billing customers are responsible for all other charges applicable to the customer's rate class and recovered through fixed amounts or charged at units other than kilowatt-hours, including customer and/or demand charges, as applicable.