Energy Choice Matters
December 3, 2008

WGES Urges D.C. PSC to Reconsider Retail Bid Model for SOS

The District of Columbia PSC should consider moving forward with a "retail bid model" approach to SOS before permanently codifying rules for the current wholesale model, Washington Gas Energy Services said in comments on the SOS NOPR (FC 1017, Matters, 12/2/08).

Under the retail bid model, licensed retail electric suppliers would bid to serve all or a portion of full requirements load for each customer class, most analogous to Maine's Standard Offer Provider structure. Unlike retail load auctions that have been debated (and rejected) in other jurisdictions, retail suppliers in D.C. would not be assigned specific customers under the D.C. retail SOS model.

A uniform SOS price for each class would be set at the weighted average of all accepted bids for retail load in a customer class. Winning bidders would be paid their actual bid prices, minus adjustments for uncollectibles associated with their load. Bids to provide SOS could be for periods up to six years.

The PSC approved rules for a retail bid model design, but shelved implementation in 2004. WGES and the Office of People's Counsel were the main proponents of the retail load auction approach. Utility Pepco, several wholesale suppliers, Pepco Energy Services and the then-named Mid-Atlantic Power Supply Association favored the ultimately adopted wholesale bid approach.

Full consideration of the retail bid SOS model, "would signal a desire to advance electric supply competition in the District of Columbia," WGES said, noting the PSC did not foreclose the possibility of returning to an examination of the retail model.

... Continued Page 6

EDF Offers $4.5 Billion for 50% Stake in Constellation Nuclear Business

Electricite de France SA has offered to acquire a 50% stake in Constellation Energy's nuclear business for $4.5 billion, in a proposal that provides $1 billion in up-front cash.

EDF said the nuclear offer represents the equivalent of an offer of around $52 per share of Constellation common stock, a financial premium of approximately 96% above the MidAmerican Energy Holdings proposal. While EDF is offering $4.5 billion for the nuclear stake, MidAmerican is offering $4.7 billion for the entire company. Constellation would remain a stand-alone company under the EDF proposal.

The offer includes an asset put option pursuant to which Constellation could, at its option, sell to EDF non-nuclear generation assets having an aggregate value of up to $2 billion.

EDF noted that, "stockholders, ratepayers, regulatory authorities, legislators and analysts have all been outspoken in their view that the MidAmerican transaction was accepted under extraordinary circumstances and is contrary to the best interests of the Company and its constituents."

EDF said it can receive the necessary regulatory approvals for its acquisition within six to nine months. Constellation had said the specter of a lengthy merger review prompted it to opt for MidAmerican's proposal over EDF in September, when it needed a quick infusion of cash. EDF's proposal would not require Maryland PSC approval, EDF reported.

EDF said its offer would provide Constellation stockholders, "with an opportunity to realize the value of their investment in the Company," and provide more than sufficient liquidity.

Earlier Tuesday, Constellation said absent the MidAmerican deal, it would likely need immediate

... Continued Page 6

Generators, Curtailment Providers Protest NYISO Special Case Resource Price Floor

A compliance filing from the New York ISO regarding mitigation of Special Case Resources (demand response) in the ICAP market drew protests from curtailment service providers as well as generators.

In a September rehearing order, FERC extended buyer-side mitigation rules, meant to prevent uneconomic entry and the associated ICAP price depression, to all sellers, including Special Case Resources (Matters, 10/01/08).

NYISO's compliance filing proposed that Special Case Resources (SCRs) be subject to an offer floor equal to, "The minimum monthly payment for providing Installed Capacity payable by its Responsible Interface Party, plus the monthly value of any payments or other benefits the Special Case Resource receives from a third party for providing Installed Capacity, or that is received by the Responsible Interface Party for the provision of Installed Capacity by the Special Case Resource."

The inclusion of incentive payments and "other benefits" drew opposition from the New York PSC and Consolidated Edison, who told FERC it would interfere with a cost-based retail distribution program, as well as overall state policies which promote demand response to bolster reliability and reduce peak load.

By imposing a bid floor that includes any incentives SCRs may receive, the NYISO's compliance filing, "will make it less likely that SCRs will either be selected by the NYISO as an ICAP provider or be willing to participate in the NYC ICAP market," the PSC said. "As a result, the availability of these demand response providers, and their associated benefits, will be seriously jeopardized," the PSC cautioned.

ConEd reported that the NYISO's proposed language would include its retail Distribution Load Relief Program (Rider U), which pays customers a cost-based rate to provide at least 50 kW of load reduction for a period of not less than four hours as designated by ConEd.

The language should be tweaked to exclude Rider U payments from the offer floor, since, *a priori*, the cost-based payment for providing distribution load relief cannot result in the subsidization of SCR providers which the bid floor is meant to prevent, ConEd said.

The NYISO's filing would subject curtailment service providers, called Responsible Interface Parties (RIPs), to a penalty if the RIP submits offers below the applicable offer floor, and such an offer causes or contributes to a decrease in UCAP prices in New York City by 5%, provided the decrease is at least $0.50/kW-month. If the RIP violates this impact threshold, it would be subject to a penalty of 1.5 times the difference between the Spot Market-Clearing Price, for the New York City Locality, for the amount of MWs that violated the offer floor. The penalty procedure would only occur after the monthly ICAP auction is held.

Demand response providers (the RIP coalition) objected to the penalty mechanism because it presumes all RIPs enter into fixed price contracts and therefore should be able to determine what the minimum offer floor for each SCR will be. The RIP Coalition members reported that they do not enter into fixed priced contracts, and in most instances enter into contacts that pay them a percentage of auction clearing prices, based on strip, monthly, and/or spot market clearing prices. Thus, "RIP's have no forward knowledge of what auction pricing might be, nor should they be forced to project pricing ahead of time and then suffer the consequences of poor projection after the fact," the coalition said.

The coalition asked FERC to affirm that since the price paid to customers on "percentage of market" contracts could go to zero, the appropriate offer floor is also zero. Coalition members include CPower, Energy Curtailment Specialists, Energy Spectrum, EnerNOC and Innoventive Power.

The Independent Power Producers of New York protested the offer floor for SCRs because it does not mirror the offer floor for generation, as required by FERC's rehearing order. The Commission's September order required that buyer-side mitigation must be applied to SCRs, "in the same manner as all other in-City market participants," IPPNY said.

New generation entrants are subject to a 75% of Net Cost of New Entry offer floor, but NYISO declined to apply that floor to SCRs, IPPNY noted.

The SCR-only offer floor developed by

NYISO will fail to prevent uneconomic entry and the suppression of ICAP prices, IPPNY insisted. Because the NYISO's unique SCR mitigation measures call for SCR bids to be audited and subjected to penalties on an *ex post* basis, an SCR is able to submit bids below its offer floor and thereby artificially suppress the clearing price if it is the marginal unit, IPPNY claimed.

"Indeed, even though a RIP should be able to calculate an SCR's Offer Floor precisely, SCRs are not even penalized by bidding below their Offer Floors if their bids do not cause clearing prices to fall by the greater of five percent of the clearing price or $.50/kW," IPPNY said.

PJM Proposes Tighter Credit Standards, Shorter Cure Period

PJM filed strengthened credit requirements at FERC to reduce credit risk and improve the matching of credit requirements to expected activity, including a change which will increase credit requirements for approximately 80% of PJM members active in the Financial Transmission Rights markets.

PJM anticipates making further credit revisions in the first quarter of 2009 to address more difficult questions, such as the appropriate levels of unsecured credit and accelerating settlement time periods.

In the current filing, meant to reduce the mutualized default risk among market participants, PJM proposed reducing the breach cure period from three business days to two business days. Additionally, PJM members would be notified of collateral defaults by market participants under the revision. Presently, members only receive notice of payment defaults. Providing notice of collateral defaults will allow members that may have ultimate exposure to defaults through default allocation assessments to better monitor their potential exposures.

PJM would also exclude Financial Transmission Rights (FTR) historical activity from the two-month peak financial security credit requirement, a change which will increase credit requirements for approximately 80% of PJM members active in the FTR markets. Absent the change, a participant that had substantial FTR gains during the past year would have a reduced credit requirement. But since past FTR results are not predictive of FTR gains in the coming year, PJM sees no reason to reduce a market participant's credit requirement for the coming year simply because it had FTR portfolio gains the prior year.

PJM is also seeking to eliminate the existing exemption from credit requirements for certain single-month FTRs in the prompt month, finding no reason to expose market participants to greater risk through such exemptions.

PJM's filing also proposed to clarify PJM's role in bilateral transactions to ensure that the transactions do not expose the PJM pool to the risks of defaults. New tariff language stresses that bilateral transactions are "non-pool" transactions that are not transactions in the PJM Interchange Energy Market, even though physical bilateral transactions must be reported to PJM solely to record the title of power.

PJM will not mutualize bilateral defaults among PJM members, and proposed that a buyer under a bilateral contract shall guarantee and indemnify PJM and PJM Members for the costs of any Spot Market Backup that is used to meet the seller's obligation to deliver energy under the bilateral contract and for which the seller has not paid PJM.

Financial Marketers Press for Allocation of Line Loss Surpluses to PJM Virtual Traders

A PJM compliance filing on distribution of transmission line loss surpluses would continue undue discrimination against virtual transactions in contravention of a FERC order, three financial marketers claimed in a filing at FERC yesterday.

An October rehearing order directed PJM to propose a method to allocate transmission line loss surpluses to market participants paying transmission costs other than network service customers, or show cause why such credits should not be paid.

PJM believes its current procedures which do not pay surpluses to virtual transactions are consistent with FERC's order. However, Black Oak Energy, Epic Merchant Energy, and SESCO Enterprises argued that since virtual traders pay the same LMP as network service users, they should be allocated transmission line loss surpluses in the same manner as network customers, since each class of market participant pays the same embedded line losses in the LMP. PJM's requirement that virtual traders and network service customers pay the same transmission line losses cannot be squared with the different treatment that occurs when it comes to the allocation of line loss surpluses, financial marketers said.

PJM should allocate transmission line loss surpluses to virtual transactions based on their volumetric share of losses in the day-ahead market, financial marketers recommended. At the very least, PJM should allocate transmission line loss surpluses to Up-To congestion transactions based on their volumetric share of losses in the day-ahead market, financial marketers said.

PJM Files Changes to External Interface Pricing

PJM has proposed tariff changes to provide for more points at which locational interface prices applicable to directly interconnected control areas are determined, and to expand the availability of locational interface pricing to all directly connected control (balancing authority) areas that are not part of larger energy markets.

Under PJM's application, the new interface pricing methodology would become effective on February 1, 2009, replacing the proxy price approach that currently applies under agreements between PJM and certain adjacent balancing authorities.

PJM's petition contains three options for setting external pricing point definitions and pricing methodologies, only two of which can be implemented by February 1, 2009.

The first method for establishing external pricing points and associated LMPs applies to external balancing authority areas that are part of a regional, centrally dispatched organization such as an RTO. PJM will use standard power flow analysis tools to determine a set of nodes external to the PJM system to represent one or more external balancing authority areas. Each node in the interface definition will be assigned to a tie line in a set of such lines which PJM shall determine for each defined Interface Pricing Point. The sensitivity of each tie line to injections at each external pricing point shall determine the weight assigned to the node associated with the tie line in the price calculation for the indicated Interface Pricing Point.

The second pricing methodology will define pricing points that aggregate multiple, directly connected or non-directly connected, external balancing authority areas that are not part of a larger, centrally dispatched organization. PJM generally will determine prices at such points in the same manner as setting prices for external RTOs, but will also provide for alternative methodologies such as "High-Low Pricing" for the relevant Interface Pricing Points. Under High-Low Pricing, the price for energy imported from the external balancing authority area will equal the lowest LMP that PJM calculates at any generator bus in the external area. The price for energy exported to the external balancing authority area will equal the highest LMP that PJM calculates at any generator bus in the external area.

The third pricing methodology, which cannot be implemented by February 1, 2009 due to software upgrades, is called Marginal Cost Proxy Pricing. Under this provision, PJM will define an Interface Pricing Point for an individual external balancing authority area or a sub-area within a directly connected external balancing authority area, and will determine prices at such points using Marginal Cost Proxy Pricing.

Under the Marginal Cost Proxy Pricing method, prices will be determined based on comparisons of LMPs with marginal costs of each unit that is on-line at the time of price determination. For imports of energy into PJM, if LMP is equal to or greater than the marginal cost of each unit that is on-line in the relevant external area, then the price at the Interface Pricing Point for that area will equal the average of the LMPs at the marginal unit(s) in the area. In the event LMP is less than the marginal cost for any online unit, the interface price will equal the minimum LMP of such unit(s). For exports from PJM to an external area, if LMP is less than or equal to the production cost of each unit that is on-line in the external area or sub-area, the interface price will equal the average of the LMPs at the marginal unit(s) in the area. If LMP is greater than production cost for any unit that is on-line, the interface price will equal the maximum LMP of such unit(s).

Under a sunset provision, Marginal Cost Proxy Pricing would not be available after

January 31, 2010, for any external balancing authority area that has not executed an inter-regional congestion management agreement with PJM. The provision is intended to provide an incentive for external balancing authority areas that have not already done so to enter into congestion management agreements with PJM, in order to facilitate more efficient congestion management across inter-regional interfaces. Inter-regional congestion management agreements, such as the PJM-Midwest ISO agreement, are the best means of obtaining accurate prices for import and export transactions, PJM said.

Briefly:

Ohio Natural Gas Enters Vectren Ohio Market
Vectren Energy Delivery of Ohio said yesterday that new entrant Ohio Natural Gas, a SouthStar Energy Services subsidiary, has commenced operations in its territory and joins IGS Energy, MXenergy and Vectren Source in marketing competitive natural gas supply to Vectren customers. Vectren credited the new Standard Service Offer, which sets a retail adder to NYMEX pricing via an auction, for fostering a more competitive market. Ohio Natural Gas had previously been marketing only at Dominion East Ohio, which also has an SSO.

Hayduk Named New President at First Choice Power
PNM Resources named Brian Hayduk as the new president of its First Choice Power retailer, effective January 1. Current President Jeff Weiser will continue to serve in his current role through the end of the year to ensure a seamless transition, PNM said. Hayduk was most recently co-founder and president of Juice Energy, which was caught up in the Lehman Brothers bankruptcy (Matters, 10/10/08). Hayduk previously had been senior vice president at Constellation NewEnergy.

Downes to Leave DPUC in June
Connecticut DPUC Chairman Donald Downes, architect of the state's move to retail electric competition, announced yesterday he will leave the Department when his term expires in June 2009. The five-member DPUC currently has two open seats. Downes has been Chairman since his appointment in 1997.

Clean Currents Offering REC Gift Cards for Holidays
Clean Currents is selling wind power REC "gift cards" for $10/REC. The gift cards can be purchased in $10 increments, with each increment equaling 1 MWh of wind power.

PJM Develops Process to Allocate Incremental ARRs
PJM filed with FERC tariff language to value and assign Incremental Auction Revenue Rights (IARRs) and Incremental Capacity Transfer Rights (ICTRs) to transmission customers and merchant transmission facilities assigned cost responsibility for 500 kV and above transmission upgrades. Customers are allocated the congestion-hedging instruments in relation to their funding of transmission upgrades which increase the Auction Revenue Rights or transfer capability of the system. The value of IARRs that become effective at the start of a Planning Period shall be determined in the same manner as annually allocated ARRs, i.e., based on the nodal prices resulting from the annual FTR auction. The value of IARRs that become effective after the commencement of a Planning Period shall be determined on a monthly basis for each month in the Planning Period, beginning with the month the IARRs become effective.

ALJ Dismisses Tara Complaints
Per a joint request from the North Texas Trade Association and Tara Energy, a Texas ALJ dismissed with prejudice complaints against Tara from the association's members, as members no longer have an interest in the proceeding (Matters, 11/27/08).

NERA Issues RFP for ComEd ARRs
NERA Economic Consulting is administering an RFP from Commonwealth Edison to sell ComEd's rights to nominate Auction Revenue Rights (ARRs) from PJM for the period June 1, 2009 to May 31, 2010. Bid packages will be due January 21, 2009 (http://www.ComEd-EnergyRFP.com).

AEP Eyeing Line to Access Upper Midwest Wind
AEP is evaluating the feasibility of building a multi-state, extra-high voltage transmission

project across the Upper Midwest to support the development of renewable energy, at an estimated cost of $5-10 billion. The 765-kV project would link the Dakotas and surrounding areas to the existing 765-kV network that ends near Chicago. The western terminus of the project would be near a 2,000-MW wind farm in North Dakota being developed by Hartland Wind Farm LLC.

Comverge Inks Austin Energy Contracts

Comverge has entered into two new multi-year contracts with Austin Energy, for the purchase and installation of additional Comverge energy management devices in residential and commercial properties. Comverge expects the contracts to generate $20 million in revenue over five years.

TVA Seeking Green Power

The Tennessee Valley Authority issued an RFP for up to 2,000 MW of renewable or "clean" power to be supplied by June 1, 2011. Aside from renewables, clean power includes combined heat and power, waste heat recovery and other low-carbon emitting resources. Proposals are due January 16, 2009.

D.C. SOS ... from 1

Over 15% of residential customers had chosen competitive suppliers before the current wholesale model SOS rules became operative in early 2005, WGES observed, with residential shopping retreating to 3% since the wholesale model was implemented.

WGES suggested that the PSC solicit comments on the retail model, which could provide an update of developments in other jurisdictions and wholesale electricity supply markets that might prompt the Commission to move forward with a retail bid model.

The PSC should eliminate the 12-month minimum stay for commercial customers returning to SOS, and limit SOS supply contracts to 12-months for mass market customers, with hourly pricing for large customers, WGES added.

EDF ... from 1

additional liquidity to cover $1.5 billion of maturing debt and a $600 million cash shortfall. Constellation would have to pay MidAmerican $593 million if the merger is not approved.