Energy Choice Matters
November 24, 2008

MEA Says Utility Portfolio Studies Ignore Benefits

Utility analyses which concluded long-term contracts and active portfolio management would increase risk and costs to ratepayers failed to fully consider the potential upside benefit that could be available from an effectively managed resource portfolio, the Maryland Energy Administration claimed in comments on the utilities' studies (Case 9117, Matters, 10/2/08).

While MEA "acknowledges that it is unclear as to what extent a managed portfolio will afford significant price reductions for SOS customers," it pointed to the experience of Maryland cooperatives as showing a managed portfolio can save money. MEA faulted the utility analyses for only considering the near-term impacts of a managed portfolio with long-term contracts, arguing that such analyses ignored that the advantages of a managed portfolio typically come about in later years as embedded resource costs tend to increase less than new additions to the portfolio.

MEA also advocated carving out a portion of SOS load for a long-term PPA or construction contract for new, renewable generation, in order to reduce price volatility, expand generation capacity and accelerate the transition to a more diverse and sustainable energy future.

Agreeing that potential above-market prices under a portfolio approach are a concern, MEA concurred with the Pepco utilities, which recommended instituting a nonbypassable surcharge to recover the out-of-market costs if migration is expected to raise SOS costs more than 5%, if a managed portfolio is chosen. Bluewater Wind, which favored keeping the current competitive procurement method except for adding a carve-out for 15 to 25-year renewable PPAs, agreed a nonbypassable surcharge would be a sound mechanism, touting its use in Delaware to pay for a Bluewater Wind contract.

The Retail Energy Supply Association, however, was "not surprised" that the utilities' analyses "unanimously and completely" showed that an Integrated Resource Plan approach to procurement would be more expensive than the existing SOS procurement process. "The evidence provided within

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WMECO Urges Nonbypassable Charge for Long-Term Renewable PPAs

The costs of long-term renewable energy contracts to be procured by Massachusetts utilities should be spread over all customers, not just basic service customers, Western Massachusetts Electric Company said in comments to the Massachusetts DPU (Docket 08-88).

The Green Communities Act requires utilities to solicit proposals for long-term green contracts twice every five years, and to enter into cost-effective contracts not exceeding 3% of load.

The obligation to procure renewable energy via long-term contract is not simply for basic service customers, WMECO noted, as the Green Communities Act requires the 3% green obligation to be calculated against the, "total energy demand from all distribution customers in the service territory."

"Because the obligation is to enter into contracts for three percent of total energy demand from all customers, and because the benefits are a cleaner environment for all residents of the Commonwealth, the cost of this procurement should be spread to all customers," WMECO said.

WMECO warned that if costs from the contracts were collected solely from basic service customers, "the cost burden on these customers would be doubled because distribution customers in WMECO's service territory currently procure approximately one-half of their energy needs from competitive suppliers." The burden would drive more customers off of basic service, potentially resulting in a situation where a continuously decreasing fraction of customers bear an increasingly larger burden.

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Calif. PUC Orders Novation of DWR Contracts

The California PUC ordered the Department of Water Resources and utilities to begin negotiations to novate DWR power supply contracts to the IOUs, in order to facilitate the return of direct access (Matters, 10/8/08).

Direct access cannot be reinstated so long as DWR remains in its supply role, and the novation process will seek to replace DWR with the IOUs as counterparties to current long-term contracts with suppliers.

A working group composed of DWR, the IOUs and PUC Staff will start by focusing on four contracts lacking novation clauses, with the initial focus on the Sempra and Coral contracts which are the subject of ongoing litigation and thus seen as the biggest challenges. The prioritization can be adjusted by the working group if DWR and the IOUs run into barriers assigning certain contracts.

The PUC reported that $128 million in ratepayer savings is possible if all contracts all novated by 2010, through, among other things, the return of DWR reserves. Savings will decline if the novation process extends beyond 2010, but would still produce a net benefit if completed by 2012.

Commissioner Timothy Simon supported the working group process and prioritization as a "reasonably cautious" approach to novation. He urged the PUC to ensure that IOUs negotiate the best possible replacement contracts, and that the Commission not rush to implement direct access as soon as possible, as the benefits of its return are indeterminate.

Ameresco Protests Loss of Gross-Up for Efficiency Capacity Value

ISO New England's proposal to eliminate the reserve margin gross-up that is applied to the capacity value of demand resources in the Forward Capacity Market inappropriately treats dispatchable demand response and energy efficiency equally, cogeneration and load reduction specialist Ameresco said in a protest at FERC.

ISO-NE is seeking to change certain Market Rule I provisions to eliminate the reserve margin gross-up starting with the 2012/2013 capacity commitment period, which is associated with the October 2009 FCM auction.

The reserve margin gross-up is the practice of increasing the demand reduction value of demand resources by a reserve-margin factor as part of a demand resource's participation in the Forward Capacity Market. The reserve-margin factor represents the Installed Capacity Requirement (ICR) for the New England region divided by the expected system peak load for the region. At present, the reserve-margin factor is approximately 1.15 or 15% above system peak load. In other words, a reserve margin gross-up of 15% would result in a demand resource with a demand reduction value of 1.00 MW receiving a capacity credit of 1.15 MW.

The reserve margin gross-up is intended to reflect the amount of extra system capacity (or reserves) that would not be needed if the system peak load could be reduced with certainty by a perfectly available resource.

However, ISO-NE reported that the system benefits associated with highly (or perfectly) available resources are already reflected in the manner in which New England's capacity needs, or Installed Capacity Requirement, is calculated pursuant to Section 12 of Market Rule I. Thus, application of a reserve margin gross-up to the capacity value of demand resources results in the under-procurement of the Installed Capacity Requirement in the Forward Capacity Auction.

Additionally, applying the reserve margin gross-up only to demand resources does not treat other resources with similar availability comparably.

The NEPOOL Participants Committee accepted the ISO's proposal with support of 71.46% at its October 10, 2008 meeting. The ISO is not seeking to eliminate the gross-up for already-procured resources because of the market disruption such action would cause.

However, Ameresco protested eliminating the gross-up for energy efficiency measures which permanently reduce the need for installed capacity reserves. While dispatchable demand may be similar to other similarly available resources which do not receive a gross up, energy efficiency measures are "fundamentally different resources" that permanently reduce system load and thus also reduce the need for system reserves, Ameresco said.

Eliminating the reserve margin gross-up

means demand resources will receive less revenue, and that demand reduction will be less economically appealing, Ameresco noted.

Ameresco saw the adjustment as a significant policy change that should not be made as a "one-off," but one that rather needs to be examined in the broader context of the FCM settlement.

Ameresco's business plan relied in part on its expectation that the reserve margin gross-up would in fact be applied to determine the capacity value of demand resources in the ISO's Forward Capacity Market, it reported.

NCPA Wants FERC to Weigh Making All of MRTU Subject to Refund

FERC should investigate implementing the entire California ISO Market Redesign and Technology Upgrade subject to refund given a, "plethora of last-minute tariff changes," the Northern California Power Agency said in comments at FERC (ER09-213).

NCPA worried the changes could create greater market disruptions than can be predicted at this time. It urged that specific changes submitted by CAISO on October 31 -- deferrals of market functionality needed to meet a February 1 go-live date -- be subject to refund. CAISO has proposed deferring functionality of:

- Enforcement of Forbidden Operating Region constraints for generating units in the Real-Time Market;
- Unlimited Operational Ramp Rate changes for generating units;
- Procurement of incremental Ancillary Services in the Hour-Ahead Scheduling Process; and
- Automation of the commitment process for Extremely Long-Start Resources.

NCPA also raised concern because changes proposed by CAISO, "undercut some of the very considerations on which this Commission based its conditional approval of the MRTU Tariff in the first place."

CAISO has proposed to limit differences in ramp rates between adjacent operating ranges on a generating unit to a 10-to-1 ratio. But CAISO's proposed solution for adjusting ramp rates if the difference between the ramp rates for two adjacent operating regions exceeds 10-to-1 is problematic because it has proposed to increase the lower ramp rate instead of lowering the higher ramp rate in order to achieve a 10-to-1 ratio, the Western Power Trading Forum said.

The problem arises when a generating unit is unable to fully respond to CAISO dispatch instructions because it cannot achieve the ramp rate as adjusted by the CAISO. If the unit cannot respond to CAISO dispatch instructions, it will incur imbalance energy costs. Furthermore, a unit that cannot fully respond to CAISO dispatch instructions also may not be considered fully available according to the amount of Resource Adequacy capacity it has sold, and therefore may incur monetary penalties, WPTF noted.

Briefly:

Hess Withdraws CNG Imbalance Penalty Petition

Hess Corporation has withdrawn its petition at the Connecticut DPUC to waive imbalance penalties for over- and under-delivery of natural gas for its customers in the Connecticut Natural Gas service territory due to lack of actual consistent daily meter reads from CNG. The fundamental reason for CNG's lack of daily meter reads was a delay in the installation of new Itron meter reading devices, because CNG's metering provider was unable to secure a pole agreement with Connecticut Light and Power. Now that a pole agreement has been reached between CL&P and Itron, Itron has been installing units, and CNG has begun to receive actual meter reads. CNG expects all units to be installed by December 1, with its metering system fully operable no later than January 1, 2009. Given these developments, Hess considers its petition moot.

ESCO Clarifies N.Y. Pricing Comments due to New UBPs

Direct Energy wished to clarify statements made during a New York technical conference on changes to the Uniform Business Practices which, among other things, allow the PSC to release all customers, even large C&Is, from sales agreements without termination fees for any potential violation of the UBPs (Matters, 11/14/08). Chris Kallaher Director of Government & Regulatory Affairs for Direct Energy, stressed that his discussion regarding a risk premium in ESCO pricing since the UBP order was meant to be hypothetical and prospective, and did not reflect any actual changes to Direct Energy's pricing as a result of the order, and certainly did not reflect any knowledge of other ESCOs' pricing. While we believe we accurately quoted Kallaher, he stressed that he did not intend to imply that any Direct Energy contract since the Oct. 27 order has included a price premium. Going forward, Kallaher said the issue of the application of the contract release provision is sufficiently up in the air because its ultimate impact will not be known until the PSC rules on impending rehearing requests, at which point each ESCO, including Direct Energy, will have to make its own determination regarding any potential pricing impact.

Consumers, Detroit Ed Report Baselines Sales to Set Choice Cap

Consumers Energy reported to the Michigan PSC that its weather-adjusted retail deliveries for 2007 were 37,813,781 MWh, which may be used as the baseline for setting the 10% choice cap subject to a pending proceeding (Matters, 11/18/08). Consumers reached the total based on total deliveries of 40,162,750 MWh less wholesale delivers and a weather normalization adjustment. Detroit Edison has reported its weather-adjusted retail sales as 50,867,828 MWh.

National Energy Consulting Certified in Texas

The PUCT granted National Energy Consulting an aggregators license (Matters, 10/21/08). CEO Clay Miller was formerly with LPB Energy Consulting, as was President Craig Winfree, who was also a regional sales manager for Sempra Energy.

BGE Home Products to Relinquish D.C. Electric License

BGE Home Products and Services asked to relinquish is electricity supplier license in the District of Columbia, stating it has not served customers since December 2007.

Pepco Proposes Panda PPA Credit in D.C.

Pepco proposed distributing $24.7 million in additional divestiture proceeds to District of Columbia customers from funds left over from the Mirant settlement after Pepco paid Sempra Energy Trading to assume its obligation under the above-market. long-term Panda-Brandywine PPA (Matters, 6/24/08). Residential customers would receive a total of $4.4 million in a flat, one-time bill credit of $17.04. Non-residential customers are to receive $20.3 million via a one-time bill credit based on a rate of $0.00215/kWh applied on usage for the 12 months ended October 2008. Pepco has applied to disburse excess funds to Maryland customers as well (Matters, 11/18/08).

BPU OKs Higher South Jersey Gas BGSS Rate

The New Jersey BPU approved a 9.2% hike in South Jersey Gas' Basic Gas Supply Service rate.

Md. IRP ... *from 1*

the IOUs' own studies indicates that, if anything, the existing SOS procurement process should be modified in the direction of shorter-term, more market responsive procurement contracts rather than longer-term contracts," RESA noted.

Shorter-term contracts with lower risk premiums and increased spot market purchases are even more beneficial in the new credit-constrained financial environment, RESA added, pointing to recent SOS procurements which have included large risk premiums (Matters, 10/28/08).

As exclusively reported by *Matters*, Staff's bid monitor Liberty Consulting Group suggested Maryland should consider moving to shorter-term, not longer-term, SOS contracts due to the unusually high cost of capital necessary to support long-term contracts. Liberty Consulting noted it would make economic sense to hedge less given the risk premiums in the current and longer-term contracts.

RESA objected to the recommendation of the Pepco utilities to move the SOS Type I laddering period to three years, instead of the current two. To reduce risk premiums, RESA recommended moving to a 12-month laddered residential and Type I SOS structure. Utilities would procure 12-month full requirements supply twice annually, with each procurement for 50% of load. Each 12-month contract would have two seasonal prices, requiring two retail price changes per year.

But the PJM Power Providers Group (P3) said the electricity market is sufficiently liquid to support three-year contracts as suggested by Pepco.

Mass. Green ... from 1

"At the end of this spiral, all customers could leave Default Service and no one would be left to pay the possible stranded costs," WMECO said.

But the Cape Light Compact insisted that the General Court did not intend for the long-term renewable contracting process to affect customers on competitive supply in an inequitable manner. Requiring competitive supply customers to pay for the long-term contracts, when they do not receive any direct benefits from the long-term contracts, would be unfair, the Compact said.

To minimize this problem, the Compact suggested that the DPU require distribution companies to elect up-front whether to use the energy and RECs from the long-term contracts for basic service customers and RPS obligations, or to sell the energy and RECs into the market. The election should be for the duration of the term of the contract.

"This approach will prevent distribution companies from using this election provision to game the market," the Compact stressed. According to the Compact, distribution companies could "easily" take advantage of the election provision to use energy and RECs from the contracts for basic service and RPS obligations when doing so would be financially advantageous, and then switch when selling energy and RECs into the market would be more financially advantageous.

If a utility elects to use energy and RECs from a contract for basic service and RPS obligations, only basic service customers should be subject to payments under that contract, the Compact added. Furthermore, if such a contract becomes uneconomic, the burden for payments under that contract should remain solely on basic service customers.

Without these suggested protections, shopping customers would simply be subsidizing the long-term contracts without realizing any direct benefits from them, the Compact reasoned.

Under the Act, utilities are to be compensated for taking on the risks of long-term contracts, in an amount equal to 4% of the annual long-term contract payments. The Act, the Compact argued, does not require such remuneration to be paid by all distribution customers, and thus should only be paid by basic service customers.

A major point of contention among stakeholders is whether the contract should be only for RECs, or should include energy, capacity, or other combinations of products.

National Grid and Nstar favored allowing the utilities to choose which products to procure, with the leeway to determine whether contracts should be bundled or not. WMECO insisted that any contracts must include RECs. "Contracts without RECs are not renewable energy and should not be considered," WMECO said.

The Conservation Law Foundation recommended buying bundled energy and REC contracts because facility owners can balance energy and REC market risks against each other if these attributes are the subject of a long-term agreement with a single purchaser. Cape Wind Associates agreed that a full array of products, including RECs, energy and capacity, should be procured, as the legislative intent was to finance new renewable projects. Long-term revenue stability required to attract investment depends on each product, Cape Wind said.

But the New England Power Generators Association cautioned the DPU against including any non-REC products such as energy or capacity in the long-term solicitations. "By limiting long-term contracts to RECs the DPU can prevent market confusion in the electricity markets resulting from these out of market commercial arrangements," NEPGA said. The revenue stream from REC-only contracts is sufficient to facilitate financing of renewable projects, NEPGA added.

National Grid recommended that the minimum size of a project under the PPAs should be no less than 1 MW, since small projects will create the same administrative burdens for the distribution companies as large projects, but will carry fewer benefits. Grid would support aggregation of smaller projects to reach to the 1 MW threshold, as long as the projects themselves are responsible for the administration of the aggregation.

Grid and other utilities argued utilities should run their own solicitations, but the Attorney General countered that a single state procurement could produce administrative efficiencies.

National Grid suggested contracts lasting 10-15 years, for either all or a fixed percentage of the output of a project. Grid recommended a fixed price contract, with any adjustments based on a published consumer price index, for the duration of the contract. "This financial certainty should enable developers to provide more competitive contract prices," Grid said.

Pricing should not be based on conventional energy costs, such as the electric index, gas index, or oil index, National Grid said, because renewable energy is not sensitive to conventional fuel prices. Grid also opposed cost plus pricing, because such contracts are difficult to evaluate against projects with fixed prices.