Energy Choice Matters

March 31, 2009

New York Budget Only Imposes 18-a Collection Responsibility on Utilities

New York political leaders unveiled a budget Monday that eliminates draft proposals which would have levied the section 18-a assessment on ESCOs, and instead collects all 18-a costs from distribution utilities.

The budget, struck in negotiations among Gov. David Paterson, Senate Majority Leader Malcolm Smith and Assembly Speaker Sheldon Silver, continues to only impose collection of the 18-a assessment on utilities. However, in order to reflect the sales of competitive commodity supply, which are not currently subject to the assessment, the budget directs utilities to estimate the commodity supply revenues of their customers served by ESCOs, and to collect an assessment on such estimates, in addition to collecting the 18-a fee on their own commodity and delivery revenues.

Although the final mechanism of collecting the assessments will be dictated by the PSC, it is likely the all the costs would be recovered through delivery rates, making the assessment competitively neutral.

The 18-a assessment was originally designed to fund the activities of the Public Service Commission, but has been seen as another revenue source for cash-strapped New York State. The budget raises the assessment from the current one-third of one percent of revenues to two percent, and provides that such revenues may be directed to the state general fund.

While the budget must still be passed by lawmakers, changes to the 18-a provision as drafted are unlikely, given it is the product of direct negotiations among Paterson, Smith and Silver.

Pa. PUC Releases Staff Draft on Smart Metering Requirements

The Pennsylvania PUC released an updated Staff draft proposal regarding electric distribution company (EDC) smart meter procurement and installation plans (M-2009-2092655).

Act 129 requires EDCs to file smart meter implementation plans with the Commission by August 14, 2009. The legislation defines smart meter technology as including metering technology capable of bidirectional communication that records electricity usage on at least an hourly basis.

The draft provisions require that an EDC's smart meter technology must include, among other things, the following capabilities:

- Ability to provide 15-minute or shorter interval data to customers, competitive suppliers, third-parties and the RTO on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO;
- A minimum of hourly reads delivered at least once per day;
- Support for service limiting and prepaid service programs;
- Support for automatic load control by EDC, customers and third-parties, with customer consent; and

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Michigan Suppliers Report Forecast Peak Load

Several Michigan alternative electric suppliers have filed their 2009 reliability plans in response to a PSC order, which directed suppliers to report on their peak demand and supply plans (Matters, 1/14/09).

For the summer of 2009, Integrys Energy Services anticipates a peak load of approximately 87 MW.

CMS ERM Michigan LLC, which is serving industrial customer Double Eagle in Detroit Edison's territory, said its load this year is expected to be less than 40 MW.

Direct Energy Business expects to serve a peak demand of 4 MW in the Detroit Edison territory, and 1.1 MW in the Consumers Energy territory.

FirstEnergy Solutions said its peak load is ramping down from a January 2009 peak of 5 MW to a July/August 2009 forecasted peak of 3 MW and 2 MW, respectively.

MidAmerican Energy said its expected peak demand in the Detroit Edison territory is less than 1 MW.

Detroit Edison said the forecast peak demand for its service territory, including electric choice load, is 11,437 MW. The forecast coincident peak load for electric choice for the summer of 2009 is 256 MW.

Stakeholders Seek Definition of Long-Term in OEB Guidelines on Transport/Supply Contracts

The Ontario Energy Board needs to provide greater clarity regarding the definition of long-term gas transportation and supply contracts, stakeholders said in comments on draft rules which would permit natural gas LDCs to file for pre-approval of long-term transportation or supply contracts that support the development of new natural gas infrastructure.

In issuing the draft guidelines, the OEB noted that long-term supply contracts may be justified in "limited circumstances," such as when contracts are linked to long-term transportation contracts that access new resources such as LNG, or United States Rockies and Canadian frontier production. Long-term transportation contracts may help to ensure an adequate natural gas supply in the Ontario market from a diverse portfolio of sources, the Board said.

However, the Board did not define "long-term" in its report. During stakeholder discussions, there was significant disagreement over what long-term meant, the Building Owners and Managers Association of the Greater Toronto Area (BOMA) and The London Property Management Association (LPMA) noted. Long-term transportation contracts were defined as longer than one year by wholesalers and marketers, and as five years and longer by transportation and supply providers. Enbridge indicated that new transportation paths require a minimum 10-year commitment. Most stakeholders defined long-term supply contracts as longer than one year, though some commenters defined long-term supply agreements as in excess of two years, BOMA/LPMA said.

Direct Energy recommended that the term “long term contract” should be clearly defined by the Board as any contract greater than one year.

The Vulnerable Energy Consumers Coalition noted contracts typically contain evergreen and renewal provisions, and asked the Board to ensure that such provisions are appropriately captured and reviewed in its process.

Direct also reiterated its view that long-term contracting is not required by LDCs for gas supply, and said that utilities should continue with their current practice of purchasing on a monthly index basis. Accordingly, Direct recommended removing supply contracts from the rules, and only addressing long-term transportation contracts.

The final working versions of the agreements between the utilities and third parties should be also submitted for stakeholder review, prior to Board approval, Direct said.

Pike County Files April Generation Rates

Pike County Light and Power submitted to the Pennsylvania PUC default service rates for April 2009.

Class	Market Price of Supply	Supply Adjustment Charge	Default Service Charge
SC 1 Residential			
	5.9480	(2.0000)	3.9480
SC 2 General Service Secondary			
	5.9480	(2.0000)	3.9480
SC 2 General Service Primary			
	5.7450	0.1378	5.8828
SC 3 Municipal Lightning			
	5.1300	2.0000	7.1300
SC 4 Private Outdoor Lighting			
	5.1070	(2.0000)	3.1070

All prices in ¢/kWh

Marketers Say PG&E Fuel Cell Does Not Qualify for Nonbypassable Surcharge

Power marketers opposed Pacific Gas & Electric's proposed 2.9 MW fuel cell project, because it bypasses the state's competitive procurement policies and would also impose a nonbypassable surcharge on customers in a manner inconsistent with PUC precedent, the Western Power Trading Forum and Alliance For Retail Energy Markets said in a joint protest (A. 09-02-013).

PG&E's fuel cell project would result in 2.9 MW of utility-owned fuel cell capacity at two California State University (CSU) campuses.

As part of its application, PG&E requested that the project be eligible for a 10-year nonbypassable surcharge associated with any stranded costs that may result from the project. However, WPTF and AReM argued that the PUC has held that only utility-owned generation acquired as a result of "the procurement process" is eligible for recovery via a nonbypassable surcharge. The fuel cell project was not the result of a competitive RFO or other solicitation, the trade groups noted.

Furthermore, AReM and WPTF contended that PG&E's project does not meet the criteria for utility-owned generation, as PG&E has not addressed the issue of market power or urgency, and has not adequately supported any claim that the project is a preferred resource or a unique opportunity permitting utility ownership.

PG&E said in its application that utility ownership is required because the host university insisted on the arrangement. However, AReM and WPTF argued that CSU expressed concern about acquiring and owning the fuel cell itself, and that a competitive provider could equally meet such concerns through a leasing option similar to the PG&E arrangement.

Regardless, approval of PG&E's application on the grounds CSU would only accept PG&E ownership, "would set an unfavorable precedent where a utility could seek to justify further exceptions to the Commission’s rules simply by siting their developments on the property of a third party who might express their opposition to a third party development and preference for the utility to build and own generation on their property," WPTF and AReM cautioned.

The power marketers further claimed PG&E's application fails to demonstrate that the fuel cell project is warranted by “truly extraordinary circumstances” for utility ownership, or that holding a competitive RFO would be impractical.

The Division of Ratepayer Advocates also protested the application since PG&E seeks authorization to spend over $21 million of ratepayer money for a "de minimis" addition of power to the grid. DRA noted the capitalized program cost for the non-renewable generation is over $7,000/kW, or a levelized cost of 30¢/kWh. That is almost three times the current market price referent and, thus, substantially more expensive than other fossil fuel generated power.

DRA also said it was "deeply concerned" about the current trend of utilities filing for piecemeal research, development and demonstration projects, "under the guise of furthering environmentally beneficial technology," citing various IOU applications for emerging renewable research projects, separate hydrogen projects using coal and petroleum coke, and assorted renewable integration programs.

TURN expressed similar concerns about the project's cost, and its non-renewable attributes.

FERC Accepts CAISO Reduction in Unsecured Credit Limit

FERC accepted the California ISO's tariff revisions to reduce the maximum unsecured credit limit from $250 million to $150 million (ER09-589).

Dismissing arguments from J.P. Morgan Ventures, NRG Power Marketing and Powerex that the $150 million limit was still too high and exposed market participants to unacceptable levels of risk, FERC said the $150 million level represents an appropriate balance between limiting market participants' exposure to default risk, while allowing market participants to participate in the Market Redesign and Technology Upgrade markets without having to post unduly large amounts of financial security.

FERC said that the lower maximum unsecured credit limits in other RTOs cited by protesters is, in part, a function of shorter settlement cycles in those RTOs compared to the anticipated settlement cycle at the commencement of MRTU. Additionally, CAISO intends to further reduce its maximum unsecured credit limit to $50 million upon implementation of its payment acceleration program, which is anticipated to occur within a few months following the commencement of MRTU.

The Commission also approved CAISO's proposal to reduce the amount of time allowed for market participants to post additional financial security requested by the CAISO from five to three business days.

Suggestions to change the CAISO's current allocation process for the costs of payment defaults were deemed outside the scope of the proceeding by FERC, and denied. Western Power Trading Forum had recommended that defaults be allocated to all market participants pro rata based on the gross absolute value of energy injections and withdrawals, rather than through the current methodology that only imposes the costs of defaults on net creditors.

Briefly:

Md. Re-regulation Bill Heads for Senate Floor Vote

The Maryland Senate printed for third reading (a floor vote) SB 844, which would end residential and small commercial retail choice and direct the PSC to order investor-owned utilities to build ratebased generation upon a finding of need. Senators passed an amendment to the bill which mandates that the PSC "shall" implement a nonbypassable surcharge on all distribution customers for any new generation or contracted power procured at the direction of the PSC to supply bundled utility customers. The bill, before the amendment, authorized the PSC to implement an unavoidable surcharge on large customers who may still shop, but did not mandate it. The Senate also added an amendment directing the PSC to require utilities to offer renewable power to customers, rather than simply directing the PSC to consider such a mandate.

PUCO Says New AEP Ohio Rates Effective With April Billing Cycle

PUCO said in a nunc pro tunc entry that it was not the Commission's intent to allow the AEP utilities to re-bill customers at new, higher standard service offer rates for their first quarter usage, as was contemplated by inconsistent language in the Commission's electric security plan order (Matters, 3/19/09). The new rates, to replace interim rates reflecting 2008 prices used during the first quarter of the year, are not to become effective until the later of their filing with the Commission, and the utilities' April billing cycle, PUCO said.

Dayton Power Files for Transmission Cost Rider

Dayton Power and Light filed for approval at PUCO of a bypassable Transmission Cost Recovery Rider to recover various deferred and current PJM costs, including ancillary and congestion-related costs. Among other things, the rider would include Reactive Supply and Voltage Control from Generation Sources; Regulation; Synchronized (Spinning) Reserves; Operating Reserves; RPM Auction Charges; Peak Hour Period Availability Charges; Black Start Service; Transmission Congestion Charges; Transmission Losses Charges; Financial Transmission Rights Auction Charges; and Auction Revenue Rights Credits.

FERC Sets Settlement Talks on NYSEG Rebill Request

FERC set for settlement judge proceedings NYSEG's petition to rebill the New York ISO market to the tune of about $20 million due to decades-long metering errors by NYSEG and National Grid at interchange points between the utilities' transmission facilities (EL09-26, Matters, 1/23/09).

PECO Launches Supply Procurement Site

PECO has activated a website to aid generators' participation in its procurement of default service supplies for the period starting Jan. 1, 2011 (www.pecoprocurement.com). PECO's first procurement is planned for late spring 2009, pending PUC approval.

Pa. Meters ... from 1:

- Support for time-of-use and real-time pricing programs.

Furthermore, the Staff proposal would require EDCs to provide at least the following access to their smart meters and data:

1. Non-discriminatory access for competitive retail electric suppliers and third-parties, as well as conservation and load management service providers;
2. Open, non-proprietary two-way access for competitive electric suppliers and third-parties, as well as conservation and load management service providers.
3. Full electronic access to customers and their representatives to meter data upon customer consent.

Staff's draft would also direct the Electronic Data Exchange Working Group to create EDI capabilities for various transactions and communications no later than January 1, 2010. The draft suggests that one alternate solution to the use of EDI specifically for the purpose of smart meter technology implementation would be the use of retail energy standards and formats relating to demand response and energy efficiency that would be developed for meter level data communication by the North American Energy Standards Board. Such NAESB standards must be available for implementation no later than January 1, 2010, or at the end of the EDC generation rate cap period, Staff said. A second alternative and expedient, interim solution for market participants would be partnership with an EDI-compliant third-party contractor who, in turn, would provide data to the customer’s authorized agent in any format specified by agreement between those two parties, Staff said.

Among the questions in Staff's proposal are:

- Should the Commission establish minimum standards on how often the utility should acquire the usage data from the meter?
- Should the Commission establish minimum data intervals? If so, what should that be? [e.g. 15 minute, 30 minute, 1 hour]
- What minimum timeframe should the Commission establish on when usage data is made available by the Meter Data Service Provider (MDSP, usually the EDC) to the EDC, competitive suppliers/curtailment service providers, and customers, respectively?
- What electronic access to customer meter data do competitive suppliers/ curtailment service providers need from EDCs that they currently do not have?
- To the extent permissible under the law, should the Commission provide an incentive to EDCs to accelerate their smart meter deployment by giving a credit towards the required Energy Efficiency and Conservation Goals?