Energy Choice Matters

October 29, 2008

N.Y. PSC Staff Objects to NiMo Changes to Shoulder Month Capacity Procurement, Tolerance Level

National Grid's proposed changes to shoulder month capacity procurement should be rejected because they would place an unnecessary administrative burden on ESCOs, New York PSC Staff said in testimony in Grid's current gas rate case (08-G-0609).

Currently under SC-11 (Load Aggregation Service), gas marketers are assigned firm upstream pipeline transportation and storage capacity on Dominion Transmission, Inc. (DTI). SC-11 is the tariff service under which marketers aggregate their customers in order to participate in Grid's Supplier Select Program, pursuant to which Grid delivers marketer-owned gas to the marketer's customers. Marketers use the assigned capacity to serve their customers.

Although the assigned capacity is sufficient to meet the design (possible coldest) day requirement of the marketers' customers in the winter months (November through March), it can be insufficient on very cold days in the "shoulder" months of April and October, because one DTI contract for firm gas transportation service from storage fields is only available during the five winter months. As a result, Grid contracts for interruptible transportation (IT) pipeline capacity from DTI to cover bundled customer and ESCO customer shortfalls during very cold days in April and October.

Grid proposed that ESCO capacity shortfalls should be the ESCO's responsibility, requesting that ESCOs be required to undertake the same actions as Grid and obtain interruptible transportation capacity from DTI on days when needed.

Staff believes such a change would burden the 27 ESCOs currently operating in Grid's gas service area. Grid, Staff noted, needed to obtain interruptible transportation capacity on 21 days during the

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Certain Capacity Charges to be Bypassable for C&Is under Duke ESP Stipulation

The settlement reached by parties to set Duke Energy Ohio's electricity security plan would make certain capacity charges bypassable for non-residential customers, while also offering certain customers a shopping credit (Matters, 10/28/08).

Under the ESP, avoidable generation charges would be rolled into the price to compare (PTC), comprised of:

- Base Generation (PTC-BG, aka Little "g")
- Fuel, Purchased Power and Emission Allowances (PTC-FPP)
- Annually Adjusted Component (PTC-AAC)

Nonbypassable generation charges would include:

- System Resource Adequacy (SRA)
  - Capacity Dedication (SRA-CD)
  - Market Capacity Purchases (SRA-SRT)
- Regulatory Transition Charge (RTC)

However, Market Capacity Purchases (SRA-SRT) would be bypassable for non-residential customers that purchase competitive retail electric service, provided that such customers agree to remain off the Standard Service Offer (SSO) through December 31, 2011 and agree to pay 115% of the SSO price if they do return. Such non-residential customers shall also receive a generation price shopping credit equal to 6% of the current Little "g" price.

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FERC Approves ISO New England Plan for Compensating De-list Bids in FCM

FERC accepted ISO New England's compensation mechanism for rejected one-year de-list bids in the ISO's Forward Capacity Market, finding that protesting generators, "would like to receive the higher of the market or full cost-of-service compensation."

For resources submitting a de-list bid which is rejected for reliability reasons, the ISO proposed paying such resources their de-list bid.

Generators reacted harshly to the mechanism, calling it confiscatory and arguing that mitigation of de-list bids prevents all true risk-adjusted costs from being included.

FERC first judged the protests to be collateral attacks on prior Commission rulings on the FCM, though it still found the ISO's proposal to be just and reasonable assuming the protests were permissible.

The Commission determined that ISO-NE's proposed compensation for rejected de-list bids is the same price that the resource would receive if the clearing price was equal to the resource's de-list bid (and thus, the resource would remain in the capacity market and receive the clearing price).

"Since paying the resource its de-list bid would be just and reasonable under these conditions, given that the resource itself signaled that that price would be acceptable, we see no reason why paying the resource a higher (for example, cost-of-service) price would be reasonable when the market clearing price is below its de-list bid," FERC reasoned.

"Thus, we disagree with those generators who assert that ISO-NE is compelling them to provide service at confiscatory prices. Rather, under the proposed rules, a generator may control its own economic situation by making a choice as to the type of de-list bid it offers, based on its perception of the potential for future FCM revenues," the Commission added.

"The protesters object to the compensation proposed for resources who submit single-year de-list bids, because they wish to preserve the opportunity to offer capacity into the FCM in future years, and would like to receive the higher of the market or full cost-of-service compensation (or some equivalent compensation in excess of their going forward costs) in each year," FERC continued.

"The purpose of the New England FCM is to attract and retain sufficient capacity to maintain ISO-NE's Installed Capacity Requirement, and to do so, FCM capacity prices will need to average out over time to the cost of new entry. But while the average price over time can be expected to match the cost of new entry, the prices in individual years will vary with market conditions above and below that average level. In that light, we do not agree that a resource should be guaranteed recovery of its full cost-of-service in each year, when the resource has the opportunity to earn more in some years," FERC said.

FERC rejected arguments that units with rejected de-list bids provide "security" which is not compensated under the resource adequacy mechanism. The Commission reiterated that location is not an adequate basis for allowing such units to receive additional compensation for providing a separate security service. "While both the resource adequacy and security functions are necessary, it is not clear that the FCM should compensate resources with rejected de-list bids differently, especially when we have previously noted that specific markets exist for compensating these security functions," FERC noted.

The Commission did not equate the need to reject de-list bids as evidence that the capacity zones for a given auction were inadequate, as suggested by generators. Still, FERC encouraged stakeholders to revisit the mechanism for establishing capacity zones under limited circumstances (as presented in Connecticut for the first auction) as soon as practicable.

FERC Accepts MISO Blackstart Service Tariff

FERC accepted the Midwest ISO's blackstart service tariff, rejecting petitions from IPPs for a standard offer rate (ER08-1486, Matters, 9/22/08).

MISO developed the tariff out of reliability concerns since many new MISO entrants do not have an obligation to provide blackstart service, with some choosing to not develop blackstart capabilities. MISO concluded a financial recovery mechanism was needed to compensate entities that supply blackstart service, to provide an incentive for generators to incur otherwise potentially non-recoverable costs associated with the inclusion of blackstart service capabilities in new units.

Each Transmission Customer will pay MISO a charge for blackstart service determined by multiplying the applicable rate by the reserved capacity for a Point-To-Point customer or by network load for a Network Integration Transmission Service customer.

FERC concluded it is just and reasonable for compensation to be based on the Commission-accepted revenue requirements associated with each blackstart unit, or on the terms of a Commission-accepted Service Agreement.

Reliant Energy and Dynegy had argued MISO should also establish a standard offer rate that can be elected by any provider, as offered in other RTOs, because traditional cost-of-service rates may discourage non-utility service providers from offering blackstart services. The IPPs cited challenges in identifying and documenting the costs of older facilities that were former utility plants, and also cautioned that because such older generation facilities may be fully depreciated, rates tied to unit-specific costs may provide insufficient incentive for such generators to offer blackstart service.

But FERC agreed with MISO and stakeholders who feared a standard offer rate would be inequitable based upon the diversity in age and depreciable value of prospective blackstart units.

The Commission also rejected the IPPs' concerns about MISO holding blackstart service providers to a minimum three-year period, with termination only upon one year's written notice. While the generators noted PJM uses a two-year commitment, FERC observed that ISO New England and the New York ISO rely on three-year terms. "Moreover, Midwest ISO reasonably explains that this amount of time may be needed to arrange for replacement service under certain circumstances," FERC said.

MISO proposed that blackstart unit owners would be required to certify that costs associated with such service are not being recovered through other rates or charges, to ensure that Market Participants do not pay twice for the same blackstart service. Detroit Edison and Consumers Energy objected to such treatment as discriminatory, noting retail rates may not recover all blackstart service costs

The Commission agreed, and ruled that MISO will not be allowed to impose an affirmative duty on a blackstart unit owner to confirm that the costs associated with such service are not being recovered through other rates or charges. Nor will FERC allow MISO to require blackstart unit owners to certify that costs associated with such service are not being recovered through other rates or charges.

"As we have explained in a similar context involving reactive power, 'the notion that SPP and the transmission owners have an affirmative obligation to demonstrate that they have removed generation plant investment associated with production of reactive power from retail rates, and that they are not charging retail customers for reactive power is outside the scope of this filing, and not within the Commission's jurisdiction,'" FERC explained.

The tariff amendments take effect October 29.

Report Hits Costs of Texas Wind

Direct subsidies, tax breaks, and increased production and ancillary costs associated with wind energy could cost Texas $60 billion through 2025, Texas Public Policy Foundation said in a report yesterday.

More ominous, however, is the claim that the, "addition of wind to the ERCOT grid also potentially jeopardizes ERCOT's ability to maintain its 12.5-percent reserve margin."

The paper reasons that as more wind comes online, conventional power plants lose energy sales. "As ERCOT is an energy-only market -- where producers are paid for generation and ancillary services, rather than for building capacity -- the question becomes whether conventional sources will lose enough in energy sales to cause them to curtail their building of the additional capacity needed to maintain reserve margins," the paper said.

The report cites three major subsidies for Texas wind -- Competitive Renewable Energy Zone (CREZ) transmission lines, the Production Tax Credit, and RECs. The subsidies will total about $2.24 billion dollars annually when wind generation has reached the state's 2025 target of 10,000 MW of installed capacity, the report said. If the $2.24 billion were apportioned over the approximately 6.5 million Texas industrial, commercial, and residential users, it would run about $345 per electric customer.

While CREZ lines have been estimated to cost $5 billion, the report projects escalating labor, material and financing costs will push the pricetag to $17 billion through 2025.

Briefly:

ERCOT Complaint Against UCE Dismissed

ERCOT's complaint against Utility Choice Electric, dating from UCE's loss of Calpine as its QSE in the fall of 2005, was dismissed by the PUCT after ERCOT reported it and UCE have reached an agreement that resolves all issues in both the docket and the Alternative Dispute Resolution process. In the original complaint, ERCOT sought revocation of UCE's certificate, based on breach of the ERCOT QSE and LSE agreements caused when Calpine, UCE's QSE and supplier, abruptly terminated those services shortly before its own bankruptcy. ERCOT also said UCE had failed to pay for load assigned to UCE during a brief period when UCE was acting as an emergency QSE -- the time from when Calpine terminated its QSE agreement with UCE until the deadline for UCE to post necessary collateral as its own QSE -- though UCE disputed the invoices. ERCOT later instituted a mass transition for UCE customers, though portions of UCE's book had been transferred to other REPs ahead of the POLR drop.

PUCT Approves Two New Certificates for Reliant

The PUCT approved new REP certificates for two new Reliant Energy subsidiaries (Reliant Energy Services Texas and Reliant Energy Texas Retail), both of which may be used to transition some or all Reliant customers to facilitate the unwind of Reliant's Merrill Lynch Credit Sleeve (Matters, 10/15/08).

Stream to Relinquish Unused Certificate

Stream Energy filed to relinquish one of its currently unused REP certificates, in the interest of administrative ease. Stream Energy conducts business under certificate 10104 but in 2006 applied for another certificate for the entity SGE Energy Management, Ltd. (certificate 10124), which has never served customers.

Md. PSC Sets Hearing on Long-Term Procurement

The Maryland PSC scheduled hearings on the IOUs' recently filed long-term procurement analyses for December 18-19 (Matters, 10/2/08). Stakeholder comments are due November 21 with replies due December 5 (Case 9117). The utilities' studies found portfolios using long-term contracting to be more expensive while carrying more risk.

TCPA Survey Finds Support for Electric Choice

A survey commissioned by the Texas Competitive Power Advocates found that 78% of Texans favor having a choice in power providers. Some 53% strongly favored electric choice while 25% somewhat favored competition. The poll of 801 registered voters was conducted by Baselice & Associates from Sept. 9 through Oct. 7, with a two-week break during Hurricane Ike restoration efforts. TCPA plans to rely on the results in the 2009 legislative session where deregulation will again face severe scrutiny.

Financing for Entergy Nuclear Spin-off Uncertain

Financing fundamental to Entergy's planned spin-off of its merchant nuclear units is "uncertain" in the near-term due to "unprecedented turmoil in the financial markets," Entergy said in putting the spin-off on hold while reporting earnings yesterday. Entergy's competitive unit saw quarterly earnings grow to $184 million from $155 million a year ago, mostly from higher prices for its nuclear units. The average realized price per MWh for Entergy's merchant nuclear plants was $61.59 for the quarter, up from $53.11 a year ago.

FERC OKs Use of Foreign Guaranties at MISO

FERC approved revisions modifying the Midwest ISO's credit policy to provide for the acceptance of Foreign Guaranties, subject to a compliance filing to correct the inadvertent omission of financials reported in Canadian GAAP as an acceptable format for required disclosures.

Only One Bidder has FTR Bids Withdrawn at PJM in Last Three Months

Since PJM's July status report on implementing revised Financial Transmission Rights credit requirements related to undiversified portfolios, PJM has only withdrawn the bids of one participant in the four auctions conducted since July (ER08-376). PJM withdrew the bids of one participant in the October 2008 monthly FTR auction that was held in September 2008, because the bidder had 5,917 MW tentatively cleared in the auction but failed to provide the $37.05 million additional credit that was required. In no case was additional credit required of any party when the second clearing iteration was performed, PJM said. In all cases in which a participant's portfolio was flow undiversified, the portfolio was geographically undiversified as well.

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past five years, or only about four days per year on average. Under Grid's proposal, all ESCOs would need to procure interruptible transportation capacity on those infrequent days, and several would need to obtain only a few dekatherms of such capacity.

Since Grid will still need to procure interruptible transportation capacity for its bundled customers, Staff recommended that it continue procuring such capacity for ESCOs as well, subject to reimbursement by ESCOs as currently done.

Staff also opposed changes to Grid's monthly balancing service (MBS) for daily metered transportation customers. The current MBS charge is based on a 5%, year-round imbalance tolerance, but Grid proposed making the tolerance seasonal, set at 5% in the winter and 8% in the summer. Combined with other changes, the current MBS monthly charge of $0.24433/dekatherm of Maximum Peak Day Quantity (MPDQ) would change to $0.2244 in the winter and $0.3590 in the summer.

However, Staff recommended keeping the year-round 5% imbalance tolerance. "Even though [Grid] has the flexibility in the summer to offer a wider imbalance tolerance (currently 8%), that does not mean that the ESCOs should be required to pay for such excess simply because a greater tolerance has been made available to them," Staff said.

Staff endorsed Grid's proposal to modify tariff language to recognize that assigned storage and pipeline capacity between Grid and ESCOs may need to be changed over time to reflect customer migration or changes in Grid's available upstream assets. Grid currently assigns to marketers its DTI storage capacity equal to 55% of the customer's Maximum Peak Day Quantity, and DTI pipeline capacity equal to 45% of the customer's MPDQ, the same proportions of upstream capacity used to transport gas to Grid's own bundled customers.

The new tariff language would require Grid to file any change with the Commission, which would allow Staff and ESCOs to comment on allocations. Essentially, Grid is putting ESCOs "on notice" that a future change is a possibility, Staff noted.

Staff suggested that, when feasible, any such changes in storage capacity assignment should have an effective date of April 1, which is the annual storage fill commencement date. Based on the timetable of the rate case, any changes would occur April 1, 2010, at the earliest.

Grid's proposal to eliminate standby sales service was supported by Staff. Grid had reported that marketers could game standby sales service by arbitraging price differences. Customers electing standby sales service pay a monthly demand charge based on the cost of reserving upstream pipeline and storage capacity, plus any gas supply reservation charges. Each day of the month, a marketer may nominate standby sales service, and the marketer is subsequently charged Grid's Monthly Cost of Gas for the total quantity of gas taken during that month. The fact that Grid charges the Monthly Cost of Gas for gas supplies that must be purchased on a daily basis creates an economic incentive for a marketer to purchase standby sales service on days when the daily price exceeds the monthly price, Grid said. Standby sales service can also create inefficiencies in storage injections and withdrawals, Grid added.

Grid proposed releasing to marketers upstream DTI pipeline capacity between Grid's citygate and DTI's liquid South Point market center. This will allow a marketer to purchase its own firm gas supplies on any day it so desires, and customers would retain the right to return to Grid sales service for its contract demand quantity. Marketers would have the right to optimize the released capacity when not needed; it would only be recalled by Grid if a customer returned to sales service, defaulted on payments to Grid, terminated service, or selected a new marketer.

Staff also proposed the development of two Merchant Function Charges (MFCs), as Grid's design creates rate inequities when service classes have different cost characteristics -- particularly for commodity uncollectibles. Staff suggested one MFC for residential customers and another MFC for non-residential customers to more closely align the cost characteristics. Grid reported that the overall unadjusted uncollectible rate for calendar year 2007 was 2.24% for residential customers and 0.33% for non-residential customers.

Duke Ohio ... *from 1*

Capacity charges associated with existing ratebased Duke plants would still be nonbypassable.

Most non-residential customers returning to the SSO at the 115% rate would not face a minimum stay, but mercantile customers, as set forth in R.C. 4928.01(A)(19), must remain on DE-Ohio's SSO for 12 consecutive billing cycles if they return between May 15 and September 16 of any year, unless they negotiate an exit fee at DE-Ohio's discretion.

Non-residential customers in a governmental aggregation may avoid Rider SRA-SRT and receive the 6% shopping credit if the aggregator notifies DE-Ohio 60 days prior to the start of aggregation of its intent to remain off the SSO through the ESP period, and agrees that returning non-residential customers shall return at a price equal to 115% of the SSO price.

DE-Ohio does not assess a separate charge for standby service or default service on non-residential or residential customers.

Proposed generation rates and shopping credits by rate class can be found in docket 08-920-EL-SSO.

A stakeholder collaborative is to develop standards for Duke's electronic bulletin board which is to promote competitive supply offers. The bulletin board is to be a competitively neutral, open access platform and may utilize a third party independent operator. The design and cost of developing and maintaining the bulletin board shall be discussed in the collaborative.

DE-Ohio's base generation charge (PTC-BG) shall reflect the unbundled generation rate as approved in Case No. 99-1658-EL-ETP less the Regulatory Transition Charge (RTC), adjusted to reflect the following:

a. The RTC for residential customers shall be eliminated on December 31, 2008;

b. The RTC for non-residential customers shall remain in effect, as an unavoidable charge, through December 31, 2010, and

c. The frozen fuel, purchased power and emission allowances currently recovered in Little "g" (1.2453¢/kWh), shall be transferred to the fuel and purchased power rider (Rider PTC-FPP), which won't affect the total price to compare;

As previously reported (Matters, 10/17/08), Duke is withdrawing its petition for a new nonbypassable charge for "newly dedicated" capacity (Rider SRA-NDC), which would have imposed an unavoidable charge for existing capacity not previously allocated to Duke's customers. The stipulation recommends that PUCO authorize Duke to make market purchases to fill its short capacity position in a least cost manner with cost recovery through Rider SRA-SRT.

DE-Ohio shall procure capacity in an open, nondiscriminatory, and competitive manner, and capacity contracts shall be awarded to the lowest and best offer. However, Duke is not required to solicit bids through a formal RFP overseen by an independent third party. Rider SRA-SRT may include compensation for capacity owned by DE-Ohio or its affiliates that has never been in Duke's ratebase.

The stipulation requests Commission approval for DE-Ohio to transfer several gas-fired plants, not currently in ratebase, to Duke's merchant affiliate. Duke reserves the right to apply to transfer currently ratebased assets to its competitive affiliate in a subsequent case.

DE-Ohio is withdrawing is proposal for an avoidable annual generation inflation adjustment (Rider PTC-IA).

Midwest ISO costs for net congestion and losses shall be recovered through Rider PTC-FPP, including the net revenue received from financial transmission rights and auction revenue rights. Ancillary services shall be recovered through the avoidable transmission charge, Rider TCR.

DE-Ohio shall not enter into arrangements for discounted rates without making a public application to the Commission and receiving the Commission's approval.