Energy Choice Matters

June 23, 2010

N.H. PUC Opens Investigation of Impacts of Migration on Default Service

The New Hampshire PUC has opened a proceeding (DE 10-160) to investigate issues related to customer migration at Public Service of New Hampshire and PSNH's practices for procuring power not supplied by its owned generation.

The proceeding will specifically investigate whether PSNH's suggested creation of a nonbypassable mechanism to bill a portion of default energy service charges to all customers is permitted pursuant to New Hampshire law and is a reasonable way to address the cost impacts of customer migration on non-migrating energy service customers.

The PUC had rejected PSNH's request for a blanket nonbypassable charge to recover all surplus energy costs in PSNH's application to set the 2010 energy service rate (Only in Matters, 1/5/10), though the PUC did make some discrete charges nonbypassable, including above-market costs associated with the replacement agreement for the Bio-Energy IPP purchased power agreement

In May testimony supporting a requested adjustment to the energy service rate, PSNH reiterated its desire to remove a portion of the current energy service costs from the bypassable energy service rate and recover such costs through a nonbypassable rate applicable to all customers. "Such a recovery would then fairly spread the cost of back up supply to all customers, not just small customers," PSNH said.

Most customers remaining on default energy service, "are the residential customers and the smaller commercial customers that have less of an opportunity to choose third party supply," PSNH

Continued P. 5

AReM Opposes Consideration of SB 695 Stranded Cost Issue in PG&E RFO Decision

Establishing a nonbypassable "Net Capacity Cost Charge" authorized under SB 695 and Section 365.1 to recover stranded costs associated with the Pacific Gas & Electric-Mirant Marsh Landing PPA is premature and prejudges the SB 695 treatment of stranded costs, the Alliance for Retail Energy Markets said in comments on a proposed decision regarding PG&E's 2008 Long-Term Request for Offers (A.09-09-021).

As only reported in *Matters*, the proposed decision would adopt a partial settlement regarding cost allocation that, for the Mirant Marsh Landing PPA, would apply a Net Capacity Cost Charge authorized under SB 695 and Section 365.1, in lieu of recovering stranded costs through a nonbypassable charge pursuant to D.04-12-048 and D.08-09-012 (Only in Matters, 5/27/10).

The settlement provides for a Net Capacity Cost Charge methodology to determine the capacity value for a project by netting the project costs with imputed energy and ancillary services revenues based upon the California ISO day-ahead market. This net capacity cost is then allocated to benefiting customers (e.g., bundled utility, Community Choice Aggregation, and direct access customers) based upon their pro-rata share of the coincident peak load. These customers are also allocated a pro-rata share of the resource adequacy value for the resource.

The partial settlement would also use a Net Capacity Cost Charge for stranded costs related to

Continued P. 6

N.H. PUC Approves Large Customer Rates at National Grid, Unitil

The New Hampshire PUC approved default service rates for large and medium customers at Granite State Electric (National Grid) and large customers at Unitil for the three-month period beginning August 1, 2010.

Granite State Electric: Large Customer Group (G1, G2), $/kWh

	August	September	October
Base Default Service (DS) Rate	$0.07421	$0.06866	$0.06975
DS Cost Reclassification	$0.00037	$0.00037	$0.00037
DS Adjustment Reconciliation Factor	$0.00123	$0.00123	$0.00123
RPS Adder	$0.00203	$0.00203	$0.00203
Total Default Service Rate	**$0.07784**	**$0.07229**	**$0.07338**

Hess Corporation won 100% of the Granite State Electric large customer group load for this period. The RPS adder reflects an approved decrease from the current level of $0.00226/kWh.

Unitil: G1 Customers, $/kWh

	August	September	October
Basic Rate	$0.07220	$0.06124	$0.06090
RPS adder	$0.00219	$0.00219	$0.00219
Total Energy Service Rate	**$0.07439**	**$0.06343**	**$0.06309**

Cargill Power Markets won 100% of the G1 default service load at Unitil for the period.

In Unitil's default service filing, PUC Staff raised an issue regarding allocation of uncollected costs between G1 and non-G1 customers. Unitil currently allocates uncollected costs between the two classes based on relative kilowatt-hour sales. Staff said that it would be more appropriate to allocate uncollected costs for default service based on the recorded amounts for each class, regardless of how such uncollected accounts are allocated in distribution rates.

The PUC directed Staff and Unitil to further discuss the allocation of uncollected costs between G1 and Non-G1 customers, stating that while the Commission found merit in Staff's recommendation, the issue requires further development and consideration as to the timing and method for transitioning to a new allocation method, and any costs that may be incurred in changes to the billing system.

Briefly:

Keytex Energy Solutions Seeks to Broker Pa. Residential Customers

Keytex Energy Solutions LLC applied to amend its Pennsylvania electric broker license to permit the brokering of residential customers. "Our intention is to offer our service to the employees, students, etc. of our commercial and industrial clients. This is a service that many of them have requested and we feel we have the expertise to perform," Keytex said.

TNMP Suspending DNPs due to Weather

The National Weather Service issued a heat advisory for counties in Texas New Mexico Power's North Texas service territory for Tuesday, June 22, prompting TNMP to suspend disconnects for non pay through Thursday, June 24, in that region. The affected region covers 17 municipalities and 46 counties.

Starion Energy Receives Additional Equity Financing

Since March, Starion Energy has raised an additional $127,000 in equity financing as part of its $3.1 million offering, it reported in an SEC filing, bringing its total from the offering to $977,000.

Reliant Further Refines Future Electric Vehicle Charging Plan

Reliant Energy has further refined its previously announced concept for an electric plan for electric vehicle charging priced as a flat fee per month, according to a report today in the *Dallas Morning News*. The product and pricing strategy was first reported by *Matters* in February (2/5/10). The *Morning News* reported an expected lower pricing point of $60-80 for the product to be rolled out next year, versus the $80-100 range envisioned by NRG CEO David Crane in February.

BGE Says FERC Loses Sight of Core Function in SECA Order

BP Energy Company sought rehearing of FERC's order on the Seams Elimination Charge Adjustment (SECA) initial decision, arguing that it was improperly allocated SECA charges related to retail load served by Green Mountain Energy (ER05-6 et. al.).

As only reported in *Matters*, FERC said that as Green Mountain Energy did not take transmission service from the Midwest ISO, Green Mountain Energy cannot be allocated SECA fees. FERC said that any charges related to Green Mountain's load should be paid by its supplier, BP Energy, as BP Energy was the entity taking transmission service under the arrangement (Only in Matters, 5/24/10).

BP Energy objected to what it called FERC's shift-to-shipper allocation by arguing that Green Mountain Energy withdrew its shift-to-shipper claim against BP in February 2006. As the claim against it was withdrawn, BP said that it had no notice that it could be allocated SECA fees during the case, and thus was deprived of due process.

Quest Energy (Integrys Energy Services) sought rehearing of the Commission's rejection of its shift-to-shipper claim against Mirant Americas Energy Marketing. Integrys Energy Services argued that the factual situations concerning its supply agreement with Mirant Americas Energy Marketing and the Green Mountain-BP supply agreement are nearly identical, yet FERC reversed the Initial Decision and denied Quest's shift-to-shipper claim to Mirant, while essentially shifting Green Mountain's charges to its supplier.

Integrys Energy Services and Green Mountain both sought rehearing of FERC's acceptance of the collection of SECA costs for lost revenues associated with intra-PJM transactions. Green Mountain further said that the Commission erred in determining that affiliate transactions should be included in the calculation of lost revenues.

As rehearing requests are mostly the re-litigation of prior arguments, they will not all be addressed here. However, of note is Baltimore Gas & Electric's discussion in its rehearing request regarding the burden FERC has imposed on non-jurisdictional retail load through FERC's decision which found that once transmission owners have supported their claimed lost revenues with "information in their possession," the burden of proof shifts to transmission customers to provide and support adjustments to that data (see our 5/24/10 story for additional FERC reasoning).

Essentially, BGE said, "non-jurisdictional retail load has been assigned the burden of proof for all hubbing adjustments even though load is not even a party to the case."

"Nowhere in the annals of FERC ratemaking has (1) the rate applicant provided rates for another group of utilities' FERC tariff, and (2) the ratepayers under this neighboring tariff been required to get inside the territory of the rate applicant to find out what took place there in order to disprove the justness and reasonableness of the rate submitted by this foreign rate applicant that operates outside of the ratepayers' service territories. This is no joke or misstatement of what a SECA is," BGE said.

BGE noted FERC's finding cited above which holds that, "the onus is first on the transmission owners to provide and support their claimed lost revenue amount with information in their possession; once they have met that burden, the onus shifts to the transmission customers to provide and support adjustments to that data."

"In other words, the SECA filers are exempt from any requirement to provide data and to support claims," BGE said. "They only need disclose whatever information they happen to possess. The customers must adduce evidence that the information readily at hand to the transmission owners is deficient. Under this set-up, a SECA filer gets a bye with the simple disclaimer that no better information is available to it. That is exactly what they did," BGE charged.

"The Commission appears to [have] lost sight of its core function as a ratemaking body when it comes to SECAs," BGE lamented. "That is exactly what the Congress of the United States strongly intimated when it stated that its Committee conferees are 'troubled' that the SECA lacks 'a clear accounting of actual costs or proper allocation,' and the underlying information to justify the SECA is not 'even disclosed,'" BGE said.

Citing BGE Order, NEM Agrees Education Is Critical in Movement to Dynamic Rates

The National Energy Marketers Association and its members "strongly agree" that adequate education is required before transitioning default service customers to a mandatory Time of Use (TOU) rate, NEM President Craig Goodman said yesterday, in discussing the Maryland PSC's Monday decision to deny Baltimore Gas & Electric's advanced metering implementation plan for, among other reasons, the abrupt implementation of mandatory Time of Use pricing for SOS customers.

"The Maryland Commission denied a request for several hundred million dollars in both taxpayer and ratepayer funds to implement an upgrade of the BGE infrastructure with relatively little investment on the part of BGE itself. In addition, it found that implementation of mandatory Time of Use Pricing (TOU) at this early stage of the consumer's understanding of the implications of such a pricing structure could be fraught with problems that a major public education program should be implemented to address," NEM said.

"The Maryland Commission is properly concerned about the current state of consumer education in the state, particularly about an issue as sensitive as Time of Use pricing," Goodman added.

"I think the Maryland Commission is being cautious of how they spend ratepayer and taxpayer money and that is a good thing," said Goodman.

NEM is strongly supportive of efforts to educate and protect consumers during the transition to an upgraded infrastructure and smart grid rollout. However, NEM recommended transitional steps that permit the consumer to both understand this new market and associated new pricing mechanisms before customers are subject to mandatory dynamic pricing. Specifically, Goodman noted that the use of modified demand response load profiles would allow consumers to experiment with (and receive credit for) energy efficiency and demand response behavioral modifications without incurring penalties that could potentially undermine consumer acceptance of the smart grid programs.

Aside from recommending the demand response load profiles before NARUC, NEM has advocated for demand response load profiles in smart grid proceedings in New York and the District of Columbia (see Matters, 6/7/10).

"The National Energy Marketers Association has seen a significant increase in the number of members venturing out into both the implementation of demand response technologies and all manner of new innovating energy technologies. The FERC and State PUCs that are on the cutting edge of this smart energy revolution have a unique opportunity to both shape smarter, lower cost energy decisions for their consumers and to also encourage an entire new generation of high-tech energy related technologies and related economic growth in their state economies," said Goodman.

BGE Response

Apart from rhetoric, BGE indicated that it was willing to eliminate mandatory TOU rates from its smart grid proposal; however, it further said that overall, it saw no clear path forward. The PSC essentially provided a four-point plan required for advanced meter approval, which included the use of distribution rates rather than a tracker for cost recovery, non-mandatory TOU rates, and greater customer education (see 6/22/10 for full discussion).

NYISO Asks FERC to Clarify Special Case Resource Offer Floor

The New York ISO asked FERC to clarify its May 2010 order on the mitigation of the NYISO in-city ICAP market to specify that NYISO is not required to evaluate the "legitimacy" of individual state programs providing subsidies to demand response (EL07-39).

FERC's May 2010 order clarified that although Special Case Resources (SCR) must be subject to mitigation in the "same manner" as other ICAP market participants, they need not be treated exactly like resources with different characteristics (e.g. traditional large generators).

With respect to the Special Case Resource offer floor calculation, the Commission disagreed that, "subsidies or other benefits designed to encourage SCRs should be eliminated from the calculation of the offer floor." At the same time, the Commission noted that it did not intend to, "interfere with state programs that further specific legitimate policy goals." FERC also concluded that payments to Special Case Resources under the New York State Energy Research and Development Authority and Consolidated Edison programs specifically discussed in the May 2010 Order should be excluded from the offer floor calculation.

With regard to future programs, FERC directed the NYISO to file new compliance tariff sheets, setting forth proposed criteria for determining whether, "to include a specific subsidy or other benefit in its calculation of SCR offer floors."

NYISO reads the Commission's single reference to "specific legitimate policy goals" as a non-dispositive expression of FERC's desire that state programs not be disrupted, rather than a mandate that the NYISO undertake a "legitimacy analysis" of each program.

"Nevertheless, there has been considerable controversy among stakeholders over how payments to SCRs should be considered in the NYISO's offer floor calculations," NYISO reported. "Therefore, out of an abundance of caution, the NYISO respectfully requests clarification that P 137 of the May 2010 Order does not require the NYISO to distinguish 'legitimate' state programs from others for purposes of the SCR offer floor calculation."

NYISO said that its requested clarification is consistent with Order No. 719's determination that RTOs shall not be put in the position of interpreting potentially ambiguous state laws and regulations.

NYISO interprets FERC's directive as a mandate to identify criteria that consider, among other things, the potential of payments to Special Case Resources to cause uneconomic entry that would harm the capacity markets, and not evaluate the legitimacy of Special Case Resource programs, or the goals of the programs, themselves.

LG&E, KU to Continue with SPP as Independent Transmission Organization

Louisville Gas & Electric and Kentucky Utilities have withdrawn their request at FERC to retire the Independent Transmission Organization (ITO) and assume full responsibility for the LG&E/KU transmission system (ER10-191). A sale of LG&E and KU by E.ON to PPL Corp. is pending.

Due to the procedural progress to date and the approaching expiration of ITO contract with the Southwest Power Pool, LG&E and KU, "have determined that their self-provision approach is no longer reasonably achievable without unacceptable delay and uncertainty."

"Under the circumstances, retaining SPP as the Applicants' ITO is a pragmatic means of complying with FERC's transmission independence requirements and providing assurance that the Applicants' Open Access Transmission Tariff will be impartially administered," LG&E and KU said.

LG&E/KU and SPP have agreed in principle to a two-year extension of the ITO Agreement, through September 1, 2012.

PSNH ... *from 1*

said, repeating its reasoning from similar November 2009 testimony. "It was PSNH's testimony at that time [in November], and it is today [in May], that this phenomenon is unfair to the small customers remaining on the ES [energy service] rate and an unintended impact resulting from the changes brought about due to restructuring. Furthermore, large customers who have selected a third party supply benefit from PSNH's embedded supply if they elect to return to PSNH. This guaranteed back up supply is available to such customers at no cost to them. In the meantime, small customers are left with a higher ES rate as they continue to support PSNH's supply," PSNH said.

The new proceeding instituted by the PUC will also examine what other potential methods exist to address the cost impacts of migration, including, but not limited to, the targeted use of technology-based initiatives and/or targeted rate mechanisms. Though not specifically mentioned in its order instituting the proceeding, such technological or rate mechanisms could include time-of-use rates and advanced metering infrastructure, and their possible impacts on load and procurement options, which were cited by the PUC in its December 2009 order on the energy service rate as areas the Commission intended to study with respect to migration impacts.

The new proceeding will further examine the interplay of PSNH's current supplemental power purchase practices with customer migration, and whether alternative procurement strategies should be implemented. Previously, in its December 2009 order, the PUC had said that it intended to study in a successor docket competitive procurement through RFPs, purchasing through the spot market, or other market based options.

PG&E ... from 1

the Oakley Project; however, the proposed decision would reject the Oakley project making the stranded cost issue moot unless the Commission grants exceptions from PG&E on the need for the Oakley project. For other PPAs authorized by the proposed decision (Midway Sunset and Contra Costa 6 & 7), PG&E has proposed recovery of stranded costs throughout their contract terms through nonbypassable charges consistent with Decisions 04-12-048 and 08-09-012, rather than under the SB 695 mechanism.

AReM said that the proposed decision deals with the SB 695 stranded cost issues with "extreme brevity," arguing that, "the issue of the applicability of the newly enacted SB 695 to stranded cost recovery associated with facilities approved as a result of this application has received short shrift."

Noting the different stranded cost treatment of Marsh Landing versus Midway Sunset and Contra Costa 6 & 7, AReM noted, "PG&E appears to believe that it is permitted to elect which facilities receive the cost allocation treatment provided for in SB 695, and which will receive cost allocation treatment pursuant to D.04-12-048 and D.08-09-012."

"However, it is not at all clear to AReM whether or not PG&E actually has this right to make such an election - all the more reason why the provisions of the Partial Settlement Agreement should be set aside until the Commission has comprehensively dealt with all the issues associated with the implementation of SB 695 as it relates to utility procurement in the new LTPP [Long Term Procurement Planning process] docket," AReM said.

AReM noted that the Commission has already identified the appropriate venue for the consideration of stranded cost recovery under SB 695 to be the new LTPP docket, R.10-05-006.

"Given that the Commission has already determined that it intends in the upcoming LTPP rulemaking to examine what refinements need to be made to the SB 695 cost allocation methodology, approval of the Partial Settlement Agreement is simply premature in adopting SB 695-type cost allocation at this time," AReM argued.

AReM said that it is not, at this point, arguing that PG&E should be denied the right to seek SB 695 cost allocation for Marsh Landing, but only that the issue should be deferred until such time as the Commission has completed its statewide review of the topic in the LTPP.

However, in reply, PG&E called the cost allocation associated with the Marsh Landing and Oakley Projects under SB 695 an "integral part" of the partial settlement agreement. "The Commission cannot and should not defer one portion of an overall settlement to some unspecified point in the future," PG&E said.

Furthermore, PG&E noted that it is unclear when SB 695 issues will be addressed in the 2010 LTPP proceeding. The new LTPP proceeding was just initiated in May and the Order Instituting the Rulemaking indicated that some of the decisions in the new LTPP proceeding may not be made until the fourth quarter of 2011, or later. "There is no reason to defer the determination of cost recovery treatment for a year and a half or more," PG&E said. AReM noted, however, that even under such a timeline, a decision in the LTPP rulemaking on cost allocation would come well before the Marsh Landing service date of 2013.

While AReM had said that there has not been any determination that the Marsh Landing and Oakley Projects are needed for "system" reliability, PG&E called this assertion incorrect, citing the 2006 LTPP Decision, in which the Commission, "determined that PG&E's service area (i.e., the system) needed 800-1,200 MW to meet the Commission-approved planning reserve margin and to continue to provide reliable service."

"This is the reliability need that the Marsh Landing and Oakley Projects are intended to fill, consistent with the requirements of SB 695," PG&E said.

The Utility Reform Network opposed the proposed decision's finding that the 500 MW that PG&E is allowed to procure through its solar photovoltaic program under D.10-04-052 shall not count towards its current procurement allotment set forth in the LTPP. PG&E, however, said that because photovoltaic capacity is intermittent, "it is not the type of operationally flexible resource with ramping capabilities required under the 2006 LTPP Decision."