Energy Choice Matters
TUESDAY, March 30, 2010

N.Y. PSC Removes Warm Transfer Mandate from ConEd ESCO Referral Program

Consolidated Edison's expansion of the PowerMove ESCO referral program will not include a "warm transfer" requirement as originally directed, the New York PSC held in an order on rehearing.

As only reported in *Matters*, the Commission's June order expanding the referral program to new service customers required ConEd, on a pilot basis, to use a warm transfer under which the ConEd customer service representative would transfer the customer directly to the ESCO's call center (Matters, 6/4/09). By allowing the warm transfer to an ESCO call center, the ESCO would serve as an agent in the enrollment process, the Commission said in its June order.

However, ConEd raised a number of logistical concerns regarding the operation of the warm transfer (Only in Matters, 7/8/09), while the Retail Energy Supply Association called the warm transfer requirement inconsistent with the established guidelines for ESCO referral programs. In particular, RESA noted that proponents of the warm transfer process have said that when a customer is transferred to an ESCO's call center, the ESCO will be free to enroll the customer in any product that the ESCO offers, not only the discounted referral product. "This broad discretion appears to conflict with the requirements established by the Commission in connection with the referral program," RESA said (Only in Matters, 7/24/09). RESA noted that under the Commission's order establishing guidelines for referral programs, the utility is obligated to enroll the customer in the referral program and no other program.

"We agree that the 'warm transfer' approach is inconsistent with our Statewide Order on ESCO

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Revised Calif. Draft Would Remove Forward Capacity Obligation from LSEs

A revised agenda decision concerning changes to the California PUC's resource adequacy mechanism would abandon the previous proposal for a multi-year forward commitment under a bilateral approach, recognizing the incompatibility of this framework with direct access (R.05-12-013). Instead, the one-year bilateral approach, with some minor enhancements, would continue.

In a story first reported by *Matters*, an ALJ's initial proposed decision would have substantially adopted the recommended resource adequacy construct of Pacific Gas & Electric which would have maintained the current bilateral framework, but would have also imposed a three-to-five year forward obligation on load serving entities (Only in Matters, 11/4/09). Retail suppliers vigorously objected to the proposal, noting that competitive suppliers will be at a competitive disadvantage in executing bilateral capacity contracts, as they cannot rely on ratepayers to guarantee the contracts, as the utilities can (Only in Matters, 12/3/09).

The updated agenda decision incorporates these concerns. "[T]he one metric of overriding concern for this [forward bilateral] option is that it fails to enable or support direct access. In fact, as the record makes clear and the comments on the ALJ's proposed decision reiterate, requiring a multi-year forward commitment would be more difficult for ESPs than IOUs to comply with because ESPs lack ratepayer-guaranteed funding and may be less creditworthy than IOUs, and because load

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Briefly:

Jump Power Registers as ERCOT Power Marketer

Financial marketer and virtual trader Jump Power, LLC, which is active in several FERC-jurisdictional RTOs, registered with the PUCT as an ERCOT power marketer.

CenterPoint to Seek Recovery of Independent Meter Testing Costs via AMS Surcharge

CenterPoint Energy intends to seek recovery for costs of the independent testing of its advanced meters by Navigant via the advanced metering system surcharge (38039). CenterPoint also confirmed that it will share with REPs data from the in-home devices it will freely provide to up to 500 customers. Retail electric providers have also asked that distribution of the free monitors occur in a non-discriminatory manner. CenterPoint agreed to random distribution of 300 in-home devices, but wishes to use non-random distribution for the remaining 200 devices, relying on a targeted placement which would better serve the goal of addressing public concern. CenterPoint said that its process would still ensure that retail electric providers are proportionately represented. CenterPoint reserved the right, but did not say that it intended, to recover costs of the free in-home devices through the advanced metering surcharge.

Luminant ET Services to Transition to Option 2 REP

Luminant ET Services Company filed for a REP certificate amendment at the PUCT to transition from an Option 1 REP to an Option 2 REP serving a limited number of specified customers.

Brazos North Texas Units Not Needed for Reliability

ERCOT said that Brazos Electric Cooperative North Texas Units 1, 2 and 3 are not required to support ERCOT System reliability, and Brazos may cease or suspend operations according to the schedule provided in its notice of suspension of operations.

Garland to Pay $15,000 for LaaRs Violation

PUCT Staff and the City of Garland filed a settlement under which Garland would pay $15,000 to resolve Garland's failure to timely deploy its Load Acting as a Resource obligation on August 11, 2008. Garland deployed 0 MW of its 5 MW obligation within 10 minutes of ERCOT instruction, which did not meet the requirement for Garland to deploy 95% of its obligation within 10 minutes. Garland deployed 5.43 MW within 11 minutes and 19 seconds. Under the stipulation, Garland, a municipal utility, does not admit that the Commission has the statutory authority or jurisdiction to impose or assess an administrative penalty against Garland, and does not waive its claim to make such jurisdictional arguments in the future.

ISO-NE Seeks to Eliminate Unsecured Credit Except for POLR Providers

ISO New England has petitioned FERC to eliminate the use of unsecured credit for market participants that do not serve retail load at government-established rates. Additionally, ISO-NE applied to further shorten the cycle for billing and payment for Hourly Charges from once each week to twice each week (ER10-942).

ISO-NE said that load-serving entities serving their native load obligations who are entitled to recover their costs through governmentally established rates, "have a different risk profile than [the] rest of the market."

During 2009, on average, over 80 percent of the total financial assurance requirements for all Market Participants for all New England market and transmission charges were covered by the use of collateral (i.e., cash or letters of credit), leaving less than 20 percent, on average, being covered by the use of unsecured credit.

ISO-NE said that elimination of unsecured credit (with the noted exceptions) is warranted because undue reliance on unsecured credit can lead to greater risk-taking. "Entities allowed to use unsecured credit may increase their unsecured market positions beyond their capacity, or willingness, to pay," the ISO said.

Furthermore, ISO-NE said that the changes are needed to combat the sleeving of bilateral transactions, by which the credit risk associated with private contracts is effectively shifted to the ISO pool. "Specifically, some Market Participants are: (i) entering into bilateral transactions on a purely financial basis, (ii) not submitting those transactions to the ISO, (iii) bidding for and offering the energy products they have contracted for through the New England spot markets, and (iv) settling their bilateral contractual arrangements based on the difference between contract prices and the applicable spot price. While as a general matter this practice should be of no concern to the ISO or other Market Participants, where unsecured credit in the ISO markets is used to satisfy the financial assurance requirements associated with the bilateral market activity outside of the ISO markets, the costs of a default associated with the transaction are borne inappropriately by all Market Participants, rather than by the parties to the bilateral contract," ISO-NE said.

The exception of entities with government set rates would specifically apply to Municipal Market Participants, T&D Companies, and Non-Market Participant Transmission Customers. Furthermore, to be eligible to use unsecured credit pursuant to these exceptions, the entity must have an Investment Grade Rating or must be an Unrated Market Participant that satisfies a credit threshold set by ISO-NE (specific to each company based on several criteria).

The amendments filed by ISO-NE would also eliminate all uses of corporate guarantees as financial assurance. Furthermore, the revisions make the definition of Investment Grade Rating more conservative, and create new requirements for a bank to be eligible to provide a letter of credit. New limits are also placed on the amount of financial assurance that may be provided through letters of credit from a single entity.

REPs Oppose Exemption from Texas Energy Efficiency Rider for Large Commercial Customers

Allowing non-transmission level industrial and large commercial customers to opt-out of Texas' utility-sponsored energy efficiency programs (and thus no longer be allocated a portion of costs) would be contrary to PURA and outside of the PUCT's powers, the REP Coalition said in reply comments on a Staff proposal for publication concerning the standard offer utility efficiency programs (37623).

In initial comments, Wal-Mart had proposed allowing customers using in excess of 1 million kWh annually to opt out of the utility programs (and associated cost responsibility) if the customer pursues self-implemented efficiency measures.

The REP Coalition noted that PURA §39.905 establishes the criteria for which customer groups are eligible for and pay for the energy efficiency programs. Specifically, PURA §39.905(a)(3) states that the energy efficiency programs are for "residential and commercial customers." PURA §39.905(a)(6) states that notwithstanding subsection (a)(3), utilities "shall continue to make available, at 2007 funding and participation levels, any load management standard offer programs developed for industrial customers and implemented prior to May 1, 2007." PURA §39.905(b)(4) requires that "the costs associated with programs provided under this section are borne by the customer classes that receive the services under the programs."

"Allowing an opt-out provision for specific customers would be contrary to PURA § 39.905 and should not be adopted. The Commission rules cannot change PURA requirements designating which customer classes are eligible for the programs and which customer classes pay for the programs," the REP Coalition said.

Texas Industrial Energy Consumers countered that PURA intended to exempt all industrial customers from the energy efficiency program and surcharge, but the Commission has failed to implement this intent by only allowing transmission-level industrial customers to opt out. "[M]any industrial customers have distribution-level load and are therefore subject to the current rule. This includes industrial customers that take service directly from a substation, who are essentially the same as transmission customers but for one additional transformation," TIEC said, in recommending that the exemption apply to all industrial customers regardless of voltage.

Both TIEC and the REP Coalition opposed calls for a separate utility goal or target for demand response, such as that proposed by

Demand Response Texas. Demand response programs can already help a utility achieve its mandated energy efficiency goal, and such programs already fit under the demand goals established by the rule, the REP Coalition said in opposing a separate demand response carve-out.

TIEC further argued that demand response programs are best addressed through ERCOT and utility-specific cases rather than through the utility-mandated energy efficiency programs contained in the Substantive Rules. "ERCOT has the most successful market-based demand response ancillary service programs in the country. The Commission should be exceedingly wary of creating any utility-based programs that would undermine or interfere with the current ERCOT programs, which must meet strict reliability standards before they can be implemented. Additionally, the energy-only market provides incentives directly to consumers to shift loads away from high-cost periods. These market mechanisms are extremely effective and yet require no subsidies or mandates to work. Accordingly, the Commission should not force utility-based demand response programs into either the energy market or the ancillary services market," TIEC said.

Establishing a separate goal for demand response programs would also be contrary to PURA §39.905(a)(1), which requires utilities to provide energy efficiency programs in a "market-neutral, nondiscriminatory manner," and PURA §39.905(c) which requires the standard-offer programs to be technology neutral, TIEC said.

In initial comments, Wal-Mart recommended that customers who invest in energy efficiency measures, including investments made in conjunction with a utility standard offer program, should own any "environmental attributes" associated with the measures. The REP Coalition replied that such recommendations raise broad policy considerations beyond the scope of the instant rulemaking, and should be deferred.

Load Assails Proposed Wealth Transfer Masked as FERC Credit Reform

Load interests denounced FERC's NOPR to mandate weekly settlements at RTOs (which essentially targets the New York ISO whose stakeholders have refused to institute weekly settlements) as amounting to a massive wealth transfer to generators without any attendant decrease in credit risk (RM10-13, Matters, 1/22/10).

A mandatory weekly settlement cycle, with a potential move to daily settlements, was part of FERC's NOPR on RTO credit reforms which also included lower unsecured credit limits and stricter minimum requirements for market participant status. Weekly settlement is essentially in place, or being implemented, in all FERC jurisdictional RTOs except the NYISO (the California ISO is moving to weekly settlement though with an extended payment timeline).

The New York PSC, New York Consumer Protection Board, Multiple Intervenors, and New York Transmission Owners all opposed weekly settlement, citing the costs it would impose on retail customers. Indeed, a NYISO report found that weekly settlement would cost end users $6 million annually, while providing wholesale suppliers with $38 million in annual benefits. The $6 million cost, New York Transmission Owners noted, takes into account estimated benefits to loads from weekly settlement.

"However, stakeholders, representing the interests of consumers, demonstrated that those off-setting savings were significantly overstated," Transmission Owners said, reporting that the total increase in financing costs to end users, absent the offsets, will be $20 million annually. The New York PSC argued that because the NYISO's credit metrics are already so robust, weekly settlement would provide a de minimis decrease in risk.

Furthermore, the NYISO analysis failed to consider the administrative costs needed to implement weekly settlements, which Transmission Owners said would be significant.

Multiple Intervenors observed that Consolidated Edison recently sought and received approval to recover two categories of expenses related to potential weekly settlements: additional employees needed to process weekly settlements, and increased working capital requirements. "Although Multiple Intervenors does not know the total potential costs the New York utilities, as well as the energy service companies operating in New York, would incur and seek to recover from consumers, information gleaned from the utilities' rate cases suggest that weekly settlements would annually increase rates by millions of dollars above the $6 million estimate provided by the NYISO," Multiple Intervenors said.

"To put these costs in perspective, Multiple Intervenors provides the implications of weekly balancing for one of its members, the State University of New York ('SUNY'). A one mil per kWh increase in SUNY's electric rates translates to an additional $1.3 million in annual electricity expenses. That $1.3 million is equivalent to the salaries of 15 faculty members or the cost of educating 250 students. Thus, the end result of the imposition of weekly settlements could be the elimination of faculty positions and/or rejection of the applications of dozens or hundreds of students who otherwise would have been accepted into one of SUNY's colleges and universities."

"In the end, the incontrovertible facts confronting Multiple Intervenors and other NYISO market participants were that weekly settlements would result in a substantial wealth transfer to suppliers, significant additional costs for load serving entities and consumers, and an inestimable reduction in the risk of a market default or loss," Multiple Intervenors said. The New York PSC succinctly stated, "[c]learly, weekly invoicing in New York would increase retail rates, but there is no evidence specific to New York that risk reduction benefits would equal or exceed these costs."

Citing the $38 million in benefits that would accrue at the expense of end users, the New York PSC charged, "To create a windfall of this magnitude for the benefit one market sector, while other market sectors are burdened with costs, is inequitable at best and discriminatory at worst."

The New York PSC also cited the impact of weekly settlement on competitive ESCOs, notable not just for the arguments, but for the fact that the PSC saw fit to include, and highlight, the impact of the credit changes on ESCOs in its comments.

"The New York retail market is unique. Unlike its neighboring markets, New York's retail market has numerous competitive suppliers (Energy Service Companies, or ESCOs), which serve more than 50% of the State's retail sales. By contrast, the Pennsylvania, New Jersey and Maryland (PJM) market has few retail suppliers, and those few serve largely non-residential customers. Increasing the costs to LSEs for weekly invoicing, especially with doubtful offsetting financial benefits, could have a direct and negative impact on the retail competitive market in New York. ESCOs, like other LSEs, would incur increased working capital costs and increased operational costs, which could pose a barrier to entry and which could cause some ESCOs to exit the New York market. These cost increases may negatively affect the well-established competitive retail energy market in New York," the New York Commission said.

While the NOPR justified weekly settlement based on a study conducted for PJM, Multiple Intervenors denounced FERC's unsupported conclusion that the study's findings are applicable in other RTOs which have different credit standards. "There was no apparent intent that the [PJM] study form the basis for a national policy, and the study contains no evaluation or comparison of the credit policies already in place in other organized markets, or conclusions or recommendations regarding the need for changes in any other organized market. Therefore, it would be inappropriate for the Commission to rely on the study as the basis for requiring changes to all organized markets," Multiple Intervenors said.

Furthermore, Multiple Intervenors assailed FERC for its "surprising" decision to omit from the NOPR any discussion of the New York ISO's study showing that weekly settlement would result in a net cost to end users.

The NOPR also justifies shorter settlements -- perhaps even daily settlements -- because such shorter settlements are used in derivative markets. "[I]t should be noted that the primary purpose for moving to competitive electricity markets was to reduce costs for consumers, not to create a new commodity market similar to other commodity markets. Indeed, one of the most significant factors that makes the electricity markets different than other commodity markets is that the electricity markets must adhere to the requirements of the Federal Power Act, particularly the requirement in Federal Power Act §205 that '[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy ... shall be just and reasonable,'" Multiple Intervenors said.

"As explained in the NOPR, the purpose of the proposed credit reforms is 'to ensure that the credit policies in place in [the organized] markets are sufficient to reasonably protect consumers against the adverse effects of default' ... Nowhere does the Commission state that one of the purposes of the credit reforms is to increase revenues to suppliers. However, as explained above and demonstrated by the NYISO's analysis, the predominant effect of the proposal to mandate weekly settlement cycles is just that - an unnecessary and unjustified wealth transfer to suppliers," Multiple Intervenors added.

Hess Corporation stressed the need to balance the cost of credit reforms with the benefits they achieve. In this vein, Hess opposed daily settlements as creating undue administrative cost, burden, and capital expenses for LSEs. While FERC asked about "one-time" costs associated with a shortened settlement cycle for LSEs, Hess stressed that such costs are ongoing. While LSEs may incur a one-time cost to procure financing for shorter settlements, interest payments on such financing will be continuous, Hess noted.

ConEdison Solutions further noted that a daily settlement model would require all market participants to pay significantly higher administrative costs and likely degrade the quality of the initial daily invoice. "Because of the delay in obtaining retail meter readings, a daily settlement would, by necessity, be based on estimates of LSE usage and will require large true-ups when the retail metering data is processed. The only clear accomplishment of a daily settlement model is to maximize the working capital requirements of LSEs and by [sic] shifting cash to generation suppliers," ConEdison Solutions said.

The National Energy Marketers Association (NEM) warned that a settlement cycle shorter than seven days would be "problematic" for small retail marketers and would, "force some out of the market."

Should FERC decline such arguments and institute mandatory weekly settlements, the New York PSC said that municipals, utilities providing Provider of Last Resort service, and "ESCOs that provide security" should be exempt from weekly invoicing due to their lower credit risk.

Multiple Intervenors urged FERC, if mandating weekly invoicing, to institute mitigation measures to blunt the impact of higher costs on end users, using the benefits reaped by wholesale suppliers to fund such mitigation.

Generators' View

Calpine claimed that there is a "large empirical body of data indicating this [move to weekly settlements] is the single biggest driver in reducing credit risk in energy markets because it reduces the cash conversion cycle."

Based on ISO-New England's experience, Calpine urged FERC to consider, at a minimum, including in the final rule a requirement that all RTOs move to twice weekly billing within twelve months from the date of implementation of weekly billing. If after twelve months it appears a further reduction beyond twice weekly billing is feasible, the Commission should require all RTOs to move to daily billing at that time, Calpine said.

Several Constellation and NRG companies further warned that allowing NYISO and CAISO (as it stands now) to "remain out of step with the weekly settlement cycles across the country" increases the risk to market participants in New York and California, since it allows market participants active in several RTOs to use NYISO and CAISO as a "float" for other markets, exposing NYISO and CAISO to additional risks.

Unsecured Credit

Hess opposed granting municipal entities preference in continued unsecured credit or a higher limit, noting that there have been 54 defaults by municipalities between 1970 and 2009. Constellation NewEnergy and Integrys Energy Services also said that all market participant types should be treated equally, with no higher limits for munis or rate-based utilities. Constellation NewEnergy and Integrys Energy Services pointed to the failures of several rate-based municipalities and certain investor owned utilities, including Colorado Ute, Public Service New Hampshire, New Hampshire Coop, Eastern Maine Electrical Cooperative, Cajun Electric Cooperative, and Springfield City Water Light & Power, and further cited a recent *Wall Street Journal* story on the growing number of municipalities that are considering Chapter 9 bankruptcy.

While a municipality may be entitled to a higher credit limit due to its credit rating (with other entities equally rated receiving the same treatment) Hess said that nothing inherent in the mere fact that a utility is a municipality should entitle it to higher unsecured credit versus similar non-municipal entities.

BP Energy Company opposed "undue discrimination" in allocating unsecured credit, such as ISO New England's proposal to eliminate unsecured credit for market participants that do not serve retail load at government-established rates (see above story). "Such discrimination in the allocation of unsecured credit among market participants is inconsistent with the establishment of just and reasonable rates. BPEC urges the Commission to reject such discrimination both in this NOPR and in the specific docket where the proposed tariffs will be adjudicated," BP said.

NEM stressed that the NOPR’s $50 million unsecured credit limit must be clarified such that the $50 million cap applies to an individual retail marketer and is not applied in aggregate to the financing companies that back multiple retail suppliers in the marketplace.

NEM supports a clarified $50 million cap on unsecured credit, "because it should have the effect of rectifying a significant competitive advantage the regulated utilities currently enjoy in the marketplace. Regulated utilities that can trade largely on the strength of their balance sheets have had a competitive advantage vis a vis retail marketers that compete in their service territories in this regard."

Constellation NewEnergy and Integrys Energy Services also said that while the proposed $50 million unsecured credit limit may be appropriate now, FERC must ensure that it is periodically reviewed to take into account changes in market conditions, such as rising commodity prices, market heat rates changes, or new environmental laws that significantly raise the price of electricity.

Calpine said that FERC should not stop at $50 million in lowering the unsecured credit limit, and called eliminating unsecured credit, in conjunction with daily settlements, "beneficial and practical."

Other Issues

Regarding the minimum standards for market participant status (which are not proposed in detail in FERC's rule), NEM said that any criteria developed should reflect, "the unique position of retail energy marketers and their contribution to well-functioning organized wholesale electric markets. The minimum participation criteria must not be defined so as to unnecessarily restrict and/or prevent the participation of small retail marketers in the marketplace," NEM said.

Calpine requested that FERC make the changes effective January 1, 2011, rather than in June 2011.

DEFG Survey Finds Risk Management Most Available Value Added Service from Choice

The ability to elect the amount of price risk a customer is willing to take on was cited as the top value-added service available to large commercial/industrial customers though retail energy competition compared to regulation, according to the 2009 Survey on Electricity Restructuring conducted by the Distributed Energy Financial Group. The survey included some 250 industry participants.

The ability to elect either a fixed or floating product was cited by 39% of respondents as the most available value-added service offered by the competitive market compared with the regulated utility industry. Demand response or curtailment services was cited by about 15% respondents as the most readily available value-added service, followed by billing, payment, & data management options, and energy efficiency & energy management services (each just shy of 10%).

DEFG's survey also showed that about of 35% respondents believe that large commercial customers are likely to migrate to a new supplier for savings of as little 1-5%, while another 35% of respondents believe savings of 5-10% are required for large customer switching. For small commercial customers, nearly 40% of respondents believe savings of 5-11% are required to incent migration, while about 30% believe savings of 11-15% are required. Less than 10% of respondents believe small commercial customers will migrate for savings of less than 5%.

ConEd ... *from 1*

referral programs," the Commission said in its rehearing order, striking the requirement for a warm transfer.

Among the logistical problems cited by ConEd which also compelled the PSC to remove the warm transfer requirement is that under ConEd's random assignment process in the referral program, the ConEd customer service rep does not know the identity of the randomly assigned ESCO. The assignment to a particular ESCO is actually made when the customer's account record is updated overnight, with a letter notifying the customer of their ESCO generated automatically. If a warm transfer were required, the customer service rep would be required to know the identity of the random ESCO to initiate the transfer, potentially compromising the integrity of the random assignment process. Additionally, ConEd noted that a problem would arise in cases where either the customer requests, or the random assignment process results in, different electric and gas ESCOs for dual fuel customers, since a warm transfer could not occur for each ESCO. ConEd also noted that some ESCOs may not have a 24-7 call center, precluding the ability of a warm transfer when a customer calls outside of the ESCO's call center hours.

The Commission denied rehearing of its original finding that ConEd is required to defer costs of the PowerMove expansion until an assessment of such costs, and mechanism for allocating costs to ESCOs, has been developed. ESCOs had raised concerns with ConEd's statement that five new customer service reps would be required for the expanded referral program, and with the fact that such reps would not exclusively perform PowerMove-related functions, but would also handle general utility functions as well.

Calif.... *from 1*

forecast and load migration issues associated with the current program could be accentuated with a forward commitment greater than one year," the new agenda decision states.

"We determine that neither of the bilateral procurement options that includes a multi-year forward obligation adequately conforms to our stated metrics for resource adequacy, and therefore determine that the RA program should be continued in effect with a year-ahead procurement framework," the agenda decision continues.

The agenda decision finds that the recommendations of the Bilateral Trading Group best meet the PUC's resource adequacy objectives. The Bilateral Trading Group has recommended maintaining the current bilateral resource adequacy approach but with modifications including introduction of an electronic bulletin board to facilitate market liquidity and transparency along with a standardized and tradable capacity product with generator obligations placed in the CAISO tariff. Additionally, under the Bilateral Trading Group's recommendations, the utility-based backstop procurement and cost allocation mechanism adopted in D.06-07-029 would be continued with modifications to include more locationally targeted investment and to allow LSEs to opt out of such backstop procurement through demonstrated commitments to new generation on a multi-year forward basis.

The agenda decision generally adopts the Bilateral Trading Group's core elements including an electronic bulletin board, tradable capacity product, and a durable backstop mechanism that builds off (and potentially modifies as appropriate) the Cost Allocation Mechanism adopted in D.06-07-029. However, the agenda decision does not require any immediate change in the opt-out process for the

Cost Allocation Mechanism, maintaining the position (as in previous drafts) that an insufficient record exists to initiate the revised opt-out mechanism proposed by retail suppliers. However, given the changes in backstop procurement recommended by the Bilateral Trading Group as well as legislative mandates to review the Cost Allocation Mechanism, the agenda decision states the Commission will likely address the issue in its Long-Term Planning Process docket.

The agenda decision would affirm the earlier draft finding that a bilateral approach is superior to a centralized capacity market in order to retain state jurisdiction over resource adequacy, and to allow the incorporation of public policy goals (e.g. renewables, loading order) in the resource adequacy assessment.

The agenda decision would not provide for the immediate opening of a proceeding to implement the preferred resource adequacy design based on the Bilateral Trading Group's recommendations, noting that several of the recommendations are concurrently being addressed in other proceedings (such as the standard capacity product).

The agenda decision would also adopt in principle the development of a collaborative forward assessment of capacity needs with a multi-year horizon. "Even though we are not prepared to impose a multi-year procurement obligation on LSEs through the RA program, we see the forward assessment as an indispensible [sic] tool that would assist all market participants by providing high-quality official supply and demand information," the agenda decision states. The agenda decision would authorize the PUC Executive Director to spend $1 million per year for consultants to assist the Energy Division in performing the analysis necessary to develop a record in an implementation proceeding on the appropriate collaborative forward assessment. The agenda decision intends that reimbursement for any such expenditures would be paid by "some or all" LSEs through mechanisms to be developed in future proceedings.