California Independent
System Operator Corporatio

# Memorandum

**To:** ISO Board of Governors

**From:** Frank A. Wolak, Chairman, ISO Market Surveillance Committee

**Date:** July 9, 2007

***Re:*** ***Market Surveillance Committee Activities from May 4, 2007 to June 22, 2007***

---

**This is only a status report. No Board action is requested.**

The Market Surveillance Committee (MSC) held meetings on June 6, 2007 and June 8, 2007. The first was a joint Stakeholder Meeting at the California ISO in Folsom. The second meeting at the California Air Resources Board in Sacramento focused on the interaction of California's Greenhouse Gas Emissions policies with the California electricity market. This memo summarizes both meetings.

## Joint MSC/Stakeholder Meeting on June 6, 2007

### Public Comment

**Frank Wolak** called the meeting to order at 9:00 am and asked for public comment. **Rich Mettling** of Pacific Gas & Electric urged stakeholders and the MSC to exercise caution in approaching a number of the topics to be discussed during the meeting. **Brett Franklin** of the Electricity Oversight Board (EOB) asked the MSC to consider whether all of the additional payment mechanisms to generation unit owners to be discussed at the meeting were necessary for the long-term financial viability of the California electricity supply industry.

### Market Redesign and Technology Upgrade (MRTU) Load Scheduling Requirement

**Jacqueline DeRosa** of Market and Product Development gave a presentation on day-ahead scheduling requirements under MRTU. DeRosa first reviewed the Federal Energy Regulatory Commission (FERC) directives on day-ahead scheduling requirements under MRTU. FERC has requested that the California ISO develop and file interim measures to address the incentive load-serving entities (LSEs) may have to under-schedule in the day-ahead market no later than 180 days prior to the effective date of MRTU Release 1. In a later order, FERC emphasized that these measures are "not intended to prevent LSEs from taking steps to reduce the costs of serving load", and that these measures "should address the problem of persistent under-scheduling in the DAM [day-ahead market] on occasions when energy prices suggest that it would be economic to buy in the DAM." DeRosa then discussed four options considered by the ISO in its April 22, 2007 issues paper. The first would require a vertical demand bid for some percentage of the LSE's load forecast in the day-ahead market. The second would compare the LSE's day-ahead forecast to the maximum amount it bid into the day-ahead market at any price. The third option would simply rely on the financial incentives already built into MRTU to prevent under-scheduling and only implement other measures if there was persistent under-scheduling. The final option is an interim scheduling charge based on the amount of purchases a LSE made in the real-time market.

Two of the above options were subsequently explored in more detail by the ISO. The "Forecast versus Maximum Amount Bid" proposal would require LSEs to bid or self-schedule 95% of their demand forecast on-peak and 75% off-peak. The load forecast data would be submitted by each LSE by Load Aggregation Point (LAP) for each hour of the day to the ISO. There would be no bid floor on the demand bids submitted by LSEs and compliance would require comparing the day-ahead forecast to maximum demand bid into the DAM by LAP for each LSE. Stakeholders felt that without a price bid floor on the demand bids, this proposal was meaningless, because a LSE could comply with the rule by bidding its demand forecast at bid price of $0/MWh and then reducing this demand at higher prices. The second option, the "Interim Scheduling Charge" proposal, would impose a $250/MWh charge on the positive difference between actual real-time consumption and cleared day-ahead demand bids that exceeds 15% of cleared day-ahead demand bids. LSEs objected to this proposal because it compared actual withdrawals to day-ahead schedules to assess the scheduling charge. The LSEs felt that they would be penalized for large day-ahead demand forecast errors due to unexpected weather events between the day-ahead and real-time market.

There was a lively discussion among stakeholders and MSC members following this presentation. **Joseph Yan** of Southern California Edison emphasized that the Interim Scheduling Charge proposal penalizes LSEs for general market uncertainty. For example, a change in supplier offer behavior can impact the risk of penalties to LSEs. If suppliers unexpectedly submit much higher offer prices in the day-ahead market, the day-ahead schedule of the LSEs is likely to be significantly below the LSE's real-time consumption and the LSE will be subject to the Interim Scheduling Charge penalty. Yan argued that this proposal does not penalize persistent under-scheduling by an LSE. It penalizes the LSE if its consumption is greater than the threshold, regardless of the reason the threshold was passed.

**James Bushnell** of the MSC emphasized that there are legitimate economic reasons for an LSE to have a day-ahead schedule significantly less than its day-ahead forecast or actual real-time consumption. He made the distinction between actions by LSEs to find the market with lowest price and actions that LSEs take to lower prices. The former should not be penalized, but incentives should exist to prevent or limit the frequency that the latter event occurs. Specifically, any mechanism that the ISO adopts should prevent actions by LSEs to lower prices, not actions to find the market with lowest price. Bushnell also felt that hour-by-hour measurement of the extent of under-scheduling might catch a lot of noise in market outcomes and attribute it to persistent under-scheduling. He favored aggregating over a number of time periods to determine whether persistent under-scheduling had occurred. **Brian Theaker** of Williams emphasized that the key issue in designing a mechanism concerned how the word persistent was interpreted. Bushnell responded that persistent should be defined in terms of a dollar impact. He stated that market power mitigation mechanisms are costly to implement and that a substantial amount of market-efficiency enhancing behavior may be prevented by implementing an under-scheduling mechanism preemptively. Bushnell argued for a significant dollar threshold in terms of harm from under-scheduling before a mechanism was implemented to limit it.

**Greg Cook** of Market and Product Development stressed that an important consideration for the ISO is the simplicity of the mechanism because it will only remain in effect until virtual bidding is implemented. He stated that although the "Forecast versus Maximum Amount Bid" may be useless in terms of preventing under-scheduling, it does provide valuable information on this issue to FERC. On the "Interim Scheduling Charge" proposal, Cook argued for keeping the threshold for imposing the penalty large enough to avoid penalizing LSEs for market risk or actions beyond their control. He felt that the ISO's selection of 15% of the LSE's day-ahead schedule as the threshold for imposing penalties balanced the need to prevent persistent under-scheduling and against the need to avoid penalizing LSEs for actions beyond their control.

There was considerable discussion among stakeholders on the appropriate level of the threshold for the "Interim Scheduling Charge" proposal. Another issue concerned the need to provide exemptions for smaller LSEs and exemptions for all LSEs due to unexpected events in the market. **Sue Mara** of RTO Advisors argued that many smaller energy service providers (ESPs) could easily cross the 15% threshold because of the electricity consumption decisions of a few of their customers. She argued that few, if any, of these ESPs have the ability to move day-ahead prices through their unilateral actions. Therefore, there was no reason to impose under-scheduling penalties on them, because the only action they could take was to shift their demand to the market with the lower price. **Ellen Wolfe** of Resero Consulting supported exemptions for smaller players that could not move the price through their unilateral actions. She also favored exemptions from the penalty for errors in weather prediction as a way to make this proposal more palatable to LSEs.

There was also some discussion of the appropriate level of the bid floor if the "Forecast versus Maximum Amount Bid" option was implemented. However, no concrete proposals were made. Several MSC members commented that this aspect of the proposal made it unworkable, because what was a reasonable bid floor would likely change each hour of each day. Several stakeholders commented on the level of the under-scheduling penalty. LSEs typically felt that the $250/MWh penalty was too large. The generation community felt that the level was appropriate because the payoff from under-scheduling by large LSEs under certain system conditions could be substantial.

At the conclusion of this discussion, several MSC members questioned the need for an explicit mechanism to prevent under-scheduling under MRTU, even in the absence of virtual bidding. As long as California's three large LSEs continue to have fixed-price forward contract coverage of more than 90% of their final demand, these entities have little incentive to engage in persistent under-scheduling. An LSE with fixed-price forward contract coverage of 90% percent of its demand forecast is indifferent to the day-ahead price for this amount of energy at the location that the forward contract clears against. Therefore, it has no incentive to schedule less than this amount of demand in the day-ahead market, regardless of the day-ahead price. Only in those instances that the LSE's demand forecast is significantly below its actual consumption could an LSE with this level of fixed-price forward contract coverage be expected to schedule below 90% of its actual consumption in the day-ahead market. However, these events are likely to be infrequent and therefore would not qualify as persistent under-scheduling. Consequently, these MSC members felt that any mechanism that the ISO might implement raised the risk that it would penalize these sorts of outcomes and have no impact of preventing persistent under-scheduling, because there is no reason for it to occur if existing fixed-price forward contract levels by the three large LSEs are maintained under MRTU.

**Conceptual Design for Convergence Bidding**

**Margaret Miller** of Market and Product Development gave a presentation on the development of the ISO's conceptual design for convergence bidding. She first provided background on the ISO's progress to date which included a summary of the key design elements that had been previously reviewed with stakeholders. These include: (1) explicit identification of virtual bids, (2) restricting the convergence bids to the LAP level, (3) the use of the same load distribution factors for physical and virtual bids in the day-ahead and real-time markets, (4) the need for key market monitoring capabilities such as the quick ability to re-run market outcomes with and without virtual bids. Miller then discussed issues in need of further stakeholder discussion. These issues include: (1) which uplift and unit commitment charges are allocated to convergence bids, (2) credit requirements for virtual bids, and (3) position limits on virtual bids. Miller then presented a proposed timetable for stakeholder meetings to formulate a final convergence bidding proposal. Her presentation then focused on a detailed proposal for the allocation of uplift and commitment charges to convergence bids.

There were a number of stakeholder comments on aspects of the convergence bidding design. **Joseph Yan** of Southern California Edison argued for the public release of convergence bids along with market participant identifiers. Several stakeholders stated that they did not see any reason to restrict convergence bidding to the LAP level.  **Brian Theaker** of Williams felt that greater granularity in convergence bids would increase the benefits that market participants would realize from its implementation.  **Ellen Wolfe** of Resero Consulting also supported more spatial granularity in convergence bidding, as did representatives from **EPIC Merchant Energy**.  Wolfe stated that if the ISO stays with its current proposal for LAP-level convergence bidding, there should be clear criteria for moving to the nodal level that is specified in advance. **Eric Hildebrandt** of the ISO's Department of Market Monitoring (DMM) reiterated DMM's recommendation that it would be imprudent for the ISO to transition to nodal convergence bidding without the necessary market monitoring tools.  He pointed out that DMM does not yet have the capability to re-run the MRTU markets without convergence bids in order to assess the market impacts of convergence bids. **Frank Wolak** supported Hildebrandt's position, but noted that the performance of the market with convergence bidding restricted to the LAP level may not provide much useful information about how the market would perform with nodal-level convergence bidding.  He urged the ISO to set a timetable for transitioning to nodal-level convergence bidding that would be adhered to unless very strong evidence against implementing nodal-level convergence bidding was found.

**James Bushnell** suggested that position limits on the amount of convergence bids that a market participant can submit at a node may be a superior way to limit the potential harm associated with allowing node-level convergence bids.  For example, market participants could be restricted to submit some maximum MWh of convergence bids at each node.  As market participants and the ISO operators gain more experience with convergence bidding these limits can be increased.  **Frank Wolak** noted that starting with node-level convergence bidding and very small position limits could be an alternative way to implement convergence bidding, rather than initially limiting convergence bidding to the LAP level, which may also eliminate a major source of benefits of convergence bidding.

There was also an extended discussion of the rationale for allocating uplift and unit commitment costs to convergence bids.  **James Bushnell** advocated symmetric treatment of convergence bids and physical bids in the sense that any cost that was allocated to physical load should also be allocated to virtual load.  **Frank Wolak** argued for differential treatment of physical versus convergence bids to ensure that the $/MWh cost of convergence bids was significantly lower than the $/MWh cost of physical load or generation bids.  This would limit the magnitude of differences that could occur between day-ahead and real-time prices.  Wolak emphasized that setting the cost of convergence bidding too high could completely eliminate its usefulness in causing price convergence between the day-ahead and real-time markets.  He also noted that there was a risk in setting the $/MWh transaction cost of convergence bids too low.  This would simply encourage convergence bidding to exploit small price differences between the day-ahead and real-time market, with little reliability or market efficiency benefits.

**Frank Wolak** also argued that it is very difficult to allocate the costs of convergence bidding on a cost-causation basis.  He offered the example of a convergence demand bid which could increase unit commitment costs, because a higher demand causes more generation units to be committed in the day-ahead market.  However, if the convergence bidder's assessment of real-time demand is accurate, this convergence bid could avoid the need for the ISO to incur RUC costs or operate high cost fast start units in real-time to meet demand.  In short, this convergence bid could reduce overall system operating costs, rather than increase them, in spite of causing additional units to be committed in the day-ahead market.   This example illustrates the difficulty in making cost causation arguments with convergence bidding because ultimately an accepted convergence bid in the day-ahead market implies a corresponding price-taking bid in the real-time market.  Thus, any cost increases in one market may be more than reversed in the subsequent market.

**Scarcity Pricing**

**Frank Wolak** gave a presentation on scarcity pricing in other markets and how it might work in electricity markets and under MRTU. Wolak emphasized the crucial role that demand response plays in scarcity pricing in other markets. For example, in any market where a finite supply of the good is up for sale, the willingness of consumers to pay for the product sets the price. The essence of scarcity pricing is that willingness of consumers to pay for the good is what sets the price, not the willingness of suppliers to provide the product. Wolak then noted that a major problem with administrative mechanisms to set scarcity prices is that it is virtually impossible to tell the difference between true scarcity and an artificial scarcity created by suppliers to achieve the conditions necessary to invoke scarcity prices. Specifically, if all suppliers know that scarcity pricing is implemented when system reserves falls below some level, then all suppliers have a common interest in creating conditions where reserves fall below this level.

Wolak stated that the best possible way to ensure that true scarcity is the only way for scarcity prices to arise is with a price-responsive final demand in the wholesale market. This implies that scarcity prices will only be set in those instances when final demand is willing to consume less because it must pay a higher real-time price. The price-responsive final demand necessary for true scarcity pricing could be easily obtained by requiring all LSEs to submit price-responsive demand bids for some fraction of their day-ahead schedule. Wolak offered the figure of 10% of the LSE's day-ahead schedule as a possible value. A demand curve based on the actual willingness of final demanders to reduce their consumption would then be used to set scarcity prices.

Wolak noted that an additional benefit of this approach to scarcity pricing would be that it could be used to determine the level of the bid cap in the ISO's markets. Specifically, the bid cap would be raised to the level necessary to induce all LSEs to submit price-responsive demand bids into the real-time market equal to a pre-specified percentage of the LSE's day-ahead schedule. For example, if this percentage was 10%, then the bid cap would be set such that all LSEs are able to attract a sufficient amount of final demand to real-time pricing programs to be able to submit price-responsive demand bids into the real-time market equal to 10% of their day-ahead schedule. Clearly, the higher the bid cap the greater the potential costs savings to final consumers from responding to hourly wholesale prices. If the ISO determines that it needs 15% of final demand to be price-responsive in order to operate the system reliably, then the bid cap should be raised to make it economic for this amount of final demand to find it in their interest to respond to real-time prices. Wolak noted that this logic demonstrates that it is unnecessary for the energy market to be uncapped in order to provide adequate revenues to all generation unit owners without a formal capacity market.

There was substantial discussion between stakeholders and Wolak about the details of this method of scarcity pricing. Wolak noted that the current penetration of hourly meters in the California market and the plan to install hourly meters for all customers of California's three large LSEs would make this form of scarcity pricing possible. The magnitude of price responsiveness found in a number of real-time pricing experiments suggests requiring each LSE to submit 10 percent of its day-ahead schedule as a price responsive demand would be feasible at the current level of the offer cap in the ISO's energy and ancillary services markets. There was also a discussion of the need for scarcity pricing in a market with a formal capacity payment mechanism versus one without a capacity payment mechanism. Wolak responded that a scarcity pricing mechanism was necessary whether or not a formal capacity payment mechanism existed. A capacity payment mechanism provides no guarantee that adequate supply will be able to meet demand in real-time. If a substantial amount of generation units or transmission facilities are out of service or demand is unexpectedly high, the only way to ensure that the available supply equals demand is to have a sufficient quantity of price-responsive final demand. This is true whether or not a capacity payment mechanism exists. Wolak concluded that with the amount of price responsive final demand that is possible in the current

California market, a formal capacity payment mechanism is unnecessary for reliable system operation and long-term system reliability.

**Shucheng Liu** of Market and Product Development discussed the ISO process for developing a conceptual design for a scarcity pricing mechanism. He noted that the concept of scarcity pricing that Frank Wolak had presented would rely upon substantial price-responsive final demand bids. Its implementation would also require real-time meters, upgraded communication systems, and other infrastructure. Liu noted that any scarcity pricing mechanism that is implemented within the CAISO markets should anticipate the increasing development of demand response over the long-term.

Liu noted that FERC's September 2006 order directed the ISO to file tariff language for the implementation of a scarcity pricing methodology within 12 months after the start-up of the MRTU markets. This Order also directed the ISO to develop a reserve shortage scarcity pricing mechanism that applies administratively-determined graduated prices to various levels of reserve shortage. Prices should rise to reflect the increased need for reserves and energy, whether or not the shortage arises in conjunction with a generation or transmission outage, in both the day-ahead and real-time markets.

Liu then outlined five design issues that would be addressed within a stakeholder process to develop such a scarcity pricing mechanism. The first issue would define what products would be considered for scarcity, and specifically whether Regulation should be considered as well as other Ancillary Services like Operating Reserves (Spinning and Non-Spinning). Liu noted that NYISO incorporated only Operating Reserve within its scarcity pricing mechanism, while ISO-NE included both Operating Reserves and Regulation. A second issue focuses on the trigger for scarcity. Under current ISO operating procedures, when reserve requirements and forecasted load exceed available resources on a system-wide or regional basis, the CAISO may declare a Stage 1, Stage 2 or Stage 3 Emergency which imposes defined market rules for a System or Regional Reserve Deficiency. Liu suggested that the criteria of System/Regional Emergency could be used as the trigger of scarcity. The third issue focuses on defining the scarcity prices on an administratively determined demand curve. Liu noted that the demand curves of other ISOs could be used as references for the design by the CAISO. The next issue defined the granularity of scarcity pricing, and whether the ISO should have a simple system-wide scarcity pricing mechanism or the locational scarcity pricing that is employed by other ISOs. Liu noted that if local scarcity pricing were imposed, it would be advantageous for such local scarcity pricing regions to be consistent with the Ancillary Services Regions and Sub-regions within the CAISO markets. The last issue Liu outlined pertains to Resource Adequacy (RA) must-offer requirement and the Day-Ahead ancillary service market. Under the currently filed MRTU tariff, RA resources must offer into the Day-Ahead energy market, but not the ancillary service markets. If scarcity pricing is to be applied to both Day-Ahead and Real-Time markets, the RA recourse could be intentionally withheld from Day-Ahead ancillary service markets to create scarcity while overall (including both Day-Ahead and Real-Time) supply is sufficient. That could provide certain market participants with opportunities to manipulate energy price in the Day-Ahead market. Liu noted that including RA resources in the Day-Ahead ancillary service markets could be an important element of the scarcity pricing design.

Lastly, Liu noted that the ISO had posted an issues paper for the scarcity pricing conceptual design and asked stakeholders for initial comments on these or other design issues.

Several MSC members urged the ISO to implement a scarcity pricing mechanism that involved final demand in the price-setting process rather than rely on an administratively set process for setting scarcity prices that provides incentives for suppliers to create the system conditions that result in scarcity prices. A number of stakeholders also expressed a desire to use final demand rather than an administratively set process for setting scarcity prices. The discussion with stakeholders focused largely on whether it is necessary to have both scarcity pricing and a capacity market. Liu noted that the two are complementary to each other. While a capacity market would seek to achieve long-term capacity adequacy, the purpose of scarcity pricing focuses on real-time supply. The scarcity price reflects the shortage in reserve minute by minute, hour by hour. This real-time price signal can 1) encourage investment in generation and transmission resources at the right time, the right location, and with the right capacity mix and complement the long-term investment goals of a capacity market (centralized, bilateral, or hybrid) if there is one; 2) improve price responsiveness from demand response resources and increase available resources in cases of emergency; 3) incent market participants to contract forward and reduce reliance on volatile spot markets; and 4) encourage generators to increase resource availability by setting up maintenance schedules following the price signals and operating beyond economic maximum capacity during peak demand periods. **Frank Wolak** reiterated his point that with the amount of price responsive final demand that is possible in the current California market, a formal capacity payment mechanism is unnecessary for reliable system operation and long-term system reliability if a scarcity pricing mechanism that uses active demand-side participation is used to set scarcity prices.

**MRTU Interim Capacity Procurement Mechanism**

**Keith Johnson** of Market and Product Development discussed the ISO's proposal to make the current Reliability Capacity Services Tariff (RCST) structure compatible with MRTU. The motivation for this product is to allow the ISO to procure additional generation capacity when it deems this necessary under standardized terms and conditions. Johnson noted that this mechanism could be replaced by a centralized capacity payment mechanism, if the ISO decides to pursue that option.

Johnson described several key features of this interim capacity procurement mechanism. The first is the conditions and process used to trigger additional procurement by the ISO. Examples of conditions when this would occur are: (1) the LSE has failed to meet its Resource Adequacy (RA) requirements, (2) additional local capacity is required beyond the levels required by the RA process, and (3) a significant event has occurred that has invalidated the initial assumption underlying the RA process. Once designated, a backstop resource would be treated just like any other RA resource in the ISO's markets. It would have a daily must-offer obligation. It must offer \$0/MW in the Residual Unit Commitment (RUC) process and it would no longer be eligible for a frequently mitigated bid adder. The term of this contract would depend on the ISO's needs for this product subject to certain minimum durations. The capacity payment would be determined according to the initial negotiated RCST settlement and the costs of this capacity procurement would depend on the reason for the procurement.

Johnson described four topics that he wanted discussed by stakeholders and the MSC. The first is the term of this interim capacity procurement mechanism. He noted that stakeholders have argued for a sunset date for this mechanism. The second issue is the scope of the product. Several parties have advocated that the product go beyond a pure capacity product. One issue is whether this product should entail the provision of services that the ISO historically obtained from Reliability Must-Run (RMR) units. The third issue is how to price the capacity and other components of the product. A specific issue of interest is whether the actual unit or a hypothetical unit should be used to set the capacity payment. The final issue is the definition of a significant event that would trigger procurement by the ISO. Johnson then outlined the timeline for further stakeholder input and the development of a final ISO proposal.

The discussion between stakeholders and the MSC focused on several issues. The first was the duration of the payments. Specifically, when a unit was procured by the ISO, how long should the unit receive capacity payments. Here the point of debate was whether durations shorter than one year should be allowed. The second issue was the duration of this payment mechanism. Several stakeholders argued that the ISO should set credible sunset dates for this mechanism and stick to them. These stakeholders also acknowledged that this backstop capacity payment mechanism may need to exist for a substantial period of time because of the uncertainty in the current

California Public Utilities Commission (CPUC) RA process. A third point of discussion was the extent to which this process could replace the RMR contracting process. Several stakeholders argued for doing away with RMR contracts in favor of this backstop capacity payment mechanism. These stakeholders also argued for rolling in the provision of black start and dual-fuel capability into this process.

Perhaps the most controversial issue was what would constitute a significant event that would trigger capacity procurement by the ISO. The LSE community advocated a very high standard for what would constitute a significant event. Their perspective was that backstop procurement would occur very rarely. The generation community did not explicitly disagree with this perspective, but they did express the concern that if a generation unit was being used like an RA resource, it should be paid like an RA resource.

Several MSC members felt that this backstop capacity procurement mechanism would function as an upper bound on the prices that LSEs would pay for local RA capacity. Assuming the entire cost of this capacity procurement was assigned to the LSE that was short relative to its RA requirement, the maximum amount the LSE would be willing to pay for the generation unit in the RA process is the cost of this capacity purchased through the interim capacity procurement mechanism. For this reason, the MSC members urged the ISO not to make this payment mechanism too generous or this could unnecessarily raise the prices that LSEs have to pay to meet their RA requirements. MSC members also supported a very stringent standard for declaring a significant event. Without this, LSEs might have an incentive to rely on the ISO to procure necessary local capacity through this process rather than engage in the effort and expense to negotiate an RA agreement with a generation unit owner. Several MSC members also argued for the use of a benchmark unit to determine the payment mechanism rather than characteristics of the actual unit purchased. They favored a benchmark unit approach because the option of a generation unit to file for a cost-of-service contract always exists, and they did not want the backstop payment mechanism to become too lucrative for generation unit owners and therefore interfere with the RA process or become too costly to negotiate because of the need to tailor each capacity payment to the unique characteristics of each generation unit.

### Update on Demand Response

**John Goodin** of Market and Product Development summarized the current state of demand-response activities at the CPUC and ISO. There are three phases to the CPUC process. The first is methodologies for assessing the load impact and cost effectiveness of demand response programs. The second is to set demand response goals for 2008 and beyond. The final phase is how to integrate demand response into MRTU. Goodin then described several demand response working groups that were being formed to accomplish these goals. Goodin noted that the ISO will participate in these working groups and provide space on the ISO web-site, but it will be the responsibility of individual groups to organize meetings and refine the objectives and tasks of each working group.

Following this presentation, Frank Wolak adjourned the meeting at 5:30 pm.

## Greenhouse Gas Policies and Electricity Market Interactions—June 8, 2007

This meeting was designed to discuss the challenges facing California in integrating its Greenhouse Gas (GHG) emissions control policies with its electricity market policies. To this end, the MSC organized a sequence of stakeholder presentations designed to highlight the major issues and stimulate further stakeholder comment and discussion. The meeting began at 1:00 pm at the California Air Resources Board. The format of the meeting was to have several stakeholder presentations followed by MSC and stakeholder comment and questions.

**Mike Scheible** of the California Air Resources Board (CARB) led off the meeting with an overview of AB 32, the state law that establishes a cap on California's GHGs. He outlined the challenges faced by California in meeting the goals of AB 32 and what CARB's role was in achieving these goals. He then presented data on California's

GHGs with specific attention to the electricity sector. He then discussed the progress that had been made at the CPUC and the Market Advisory Committee (MAC) established under AB 32 in formulating a GHG emission control policy for California. He then introduced the distinction between a load-based cap on GHG emissions and a source-based cap on GHG emissions. Under a load-based cap, LSEs must ensure that the total carbon content of the electricity they consume is less than the amount of emission permits they possess. Under a source-based system, generation units must ensure that the total amount of GHGs they emit must be less than the amount of emissions permits they possess. He then briefly discussed the first-seller approach proposed by the MAC. Scheible concluded his talk by stating that the two major goals of AB 32 are to achieve the mandated GHG emissions reductions and design an approach to doing this that will be adopted by other jurisdictions.

**Nancy Ryan** of the CPUC then gave a presentation on the goals of the AB 32 implementation process. She emphasized that the primary goal of the process was to achieve tangible reductions in GHG emissions. She noted that although the CPUC process has been focusing on the load-based approach to implementing a cap and trade compliance mechanism, the CPUC was open to considering alternative approaches such as the MAC's first-seller approach. Ryan also stated that another goal of the AB 32 implementation process should be least cost compliance with the mandated GHG emissions reductions from AB 32. Another important consideration was whether to auction or allocate the emissions permit to market participants. Ryan expressed a preference for allocation as a way to protect consumers against rate shock. A final concern is the ability to use GHG emissions permits to raise prices in the wholesale electricity market similar to what appears to have occurred with respect to the RECLAIM market for NOx emissions permit in Southern California during the period June 2000 to March 2001.

**Audrey Chang** of the Natural Resources Defense Council (NRDC) gave a presentation comparing the load-based versus first-seller approach. The first-seller approach essentially imposes the burden of compliance with the GHG cap on the first-seller of electricity in the state. For generation units located inside California, the first seller is the generation unit. In this sense, the first-seller approach is essentially a source-based standard for in-state generation units. For imports, the first seller is the entity that imported the energy into California. Chang argued that a load-based mechanism would provide greater opportunities for energy efficiency to compete to displace new sources of supply than a first-seller based system.

Following these presentations, the MSC made several comments on the presentations. The first set of comments concerned the ability of any entity to identify where a load-serving entity purchased its energy. **Frank Wolak** noted that the laws of physics not the laws of economics guide the flow of electrons so it is impossible to determine where an LSE purchases the electrons it sells to final consumers. Wolak used the metaphor of an electricity network as a bathtub where generation unit owners injected energy at their location into the bathtub and LSEs withdrew energy at their locations from the bathtub, thereby making it impossible to determine which LSE was consuming each generation unit's energy. Consequently, the usual way to resolve this indeterminacy is to create the financial fiction that if a supplier and LSE have a forward contract for a certain amount of energy, this supplier is deemed to be the source for that LSE for the contracted quantity of energy. Using this mechanism for identifying sources, it is difficult to see why LSEs would not immediately change which suppliers they contract with in response to a source-based GHG cap, with no change in the amount GHGs produced in the western US. **Ben Hobbs** of the MSC noted that the extent to which this re-shuffling does not occur is a measure of the inefficiencies in the market for fixed-price forward contracts in the western US, because the least-cost solution to achieving compliance with a load-based cap in California would be re-shuffling of where LSEs source their generation by changing which generation units they make fixed price forward contracts purchases from.

Wolak argued more generally that unless California's GHG policy changes the dispatch of generation units outside of the state, there would be no net impact of this policy on the production of GHGs outside of the state. Put simply, if the same units outside of California operate after the California-only GHG cap-and-trade program is implemented as operated before it existed, there will be no change in aggregate GHGs produced outside of California. Wolak noted that in the absence of a GHG control mechanism outside of California, it is unlikely the coal-fired generation units located outside of California would run any less frequently because coal-fired units have very low variable costs of operation. Nuclear and renewable facilities outside of California would also tend to operate just as intensively because these are very low variable cost sources of supply. The only issue is how frequently natural gas-fired units located outside of California are operated. Because natural gas-fired units are typically the highest variable cost units operating in California, it is unclear if natural gas-fired units located outside of California will operate any less frequently after a cap-and-trade mechanism is implemented only in California. For all of these reasons, Wolak questioned the wisdom of attempting to apply California's cap-and-trade mechanism to imported electricity, because this policy is very unlikely to alter the dispatch of generation units located outside of California (and therefore unlikely to alter the production of GHGs outside of the state) but it is very likely to increase the cost of imported electricity to California consumers.

**Ray Williams** of Pacific Gas and Electric gave a presentation that contrasted a load-based GHG cap-and-trade mechanism with a first-seller approach to a GHG cap-and-trade mechanism. Williams argued that the first-seller approach would result in a more efficient dispatch of generation units in California because the costs of the GHG permits would be included in the variable cost of each generation unit located in the state. He then outlined the major compliance issues associated with implementing the first-seller approach. He argued that most of the compliance efforts associated with a first-seller-based system could be handled with pre-existing regulatory processes.

**Larry Goulder** of Stanford University and the MAC discussed the MAC report recommendations. He first discussed the reasons for the MAC's preference for a first-seller approach versus a load-based approach. The major issue he dealt with in his presentation was the contract re-shuffling issue with respect to imports. He suggested that one approach would be to assign all imported electricity in California the west-wide average carbon content.

These presentations were followed by an extensive discussion among the MSC and stakeholders on several issues. **Severin Borenstein** of the University of California Energy Institute (UCEI) questioned the logic underlying the claim that a load-based system would provide greater opportunities for energy efficiency to displace new sources of supply. He presented arguments that a source-based system would provide greater incentives for energy efficiency investments than a load-based system. Another topic receiving substantial discussion was the identity of the first-seller for the case of imports into California. Each stakeholder seemed to have a different conception of who was the first-seller into California for the case of imported electricity. There was little agreement among stakeholders precisely which entity a first-seller might be. One proposal suggested by the MAC report was to use the e-tags that the Western Electricity Coordinating Council (WECC) requires to manage electricity flows across control areas to identify the first-seller. However, as several stakeholders emphasized, e-tags typically list the originating control area, not a specific generation unit in that control area. In addition, even if the e-tag did list a specific generation unit, because of the physics of electricity flows, this specific generation unit is clearly not supplying energy to California. It would be relatively straightforward to change the identity of the generation unit listed on the e-tag selling into California if it would profitable for a supplier to do so. **Erik Saltmarsh** of the Electricity Oversight Board recalled his experience from the California electricity crisis attempting to trace the source of electricity sold into California. Saltmarsh emphasized that this is an impossible task because of the physics of electricity flows and the many layers of contracts between generation unit owners, their energy-trading affiliates, and other market participants located in and outside of California.

**Jeff Nelson** of Southern California Edison gave a detailed presentation illustrating many of the challenges associated with implementing a load-based cap-and-trade mechanism. He presented an analysis that demonstrated that under a source-based system a seller bidding into the California market would earn a market price that reflects the emissions cost of the marginal generation unit in California. That seller would therefore demand the same price to sell bilaterally to a LSE. In contrast, under a load-based cap, a seller bidding into the California market would not receive a price that reflects emissions costs. However, if the seller enters into a bilateral contract with a LSE, the LSE would be impacted by the emissions from the seller's generation unit. Thus, under a load-based system the LSE would be willing to pay a higher price for energy that is cleaner than the market average. The LSE would require a discount for power that is dirtier than the market average. As a result, clean power should sell to LSEs in long-term contracts and dirty power should sell through the California market. These incentives could create a circumstance were a large fraction of clean power self-schedules into California and only very dirty energy is willing to submit price-responsive bids into the California market. This could lead to significant reliability problems for the ISO operators because of so many inflexible clean generation units selling into California.

Nelson's presentation was followed by more discussion of potential market efficiency and system reliability problems with a load-based cap-and-trade GHG control mechanism for California. The general conclusion from these discussions was that any GHG reductions that could be accomplished with a load-based system could be accomplished with a source-based system at lower administrative and compliance costs. Several MSC members argued that because of the extreme difficulty of achieving any noticeable change in the operation of generation units outside of California as a result of a California-only GHG policy, from the perspective of achieving tangible GHG emissions reductions at least cost to California consumers, a California-only source-based cap-and-trade mechanism should be implemented. In addition, the state should work to incorporate as many states in the western US into this source-based system as rapidly as possible, because this is the least-cost approach to incorporating GHG emissions costs into the variable cost of operating fossil-fuel units outside of California. With a source-based system implemented outside of California, the dispatch of generation units outside of California would be altered because these generation unit owners would need to purchase GHG permits to produce electricity and would therefore need to incorporate GHG permit costs into the total variable cost of operating these units.

The final two presentations discussed a proposal made by the Western Power Trading Forum (WPTF) to implement a tradable emissions attribute certificates (TEACs) market. **Clare Breidenich**, a consultant for WPTF, described the essential features of the TEAC proposal which would function much like a green energy certificates market where LSEs are required to purchase a certain amount of green energy certificates and owners of renewable generation units can produce 1 MWh of green certificates for each MWh of energy they produce. Under this proposal generation units throughout the western US could sell emissions attribute certificates that reflect their actual emissions rate and the output of the generation unit. LSEs would still have to surrender emissions allowances equal to their emissions, but by the purchase of low-emissions certificates they would reduce the amount of emissions allowances they would need to have. GHG emissions allowance would be traded with other sectors of the economy, but TEACs could only be traded within the electricity sector. Breidenich then provided an example of how this mechanism would operate.

**Ben Hobbs** then made a presentation clarifying features of the WPTF proposal and design of the GHG allowance allocation process. Hobbs emphasized that the WPTF proposal creates separate tradable products—GHG emissions and MWh of energy produced—that suppliers and LSEs can trade. This opens up the possibility for a LSE to purchase energy from a dirty generation unit owner yet purchase GHG emissions from a clean one. Stated differently, it facilitates the process of contract re-shuffling described above by de-coupling energy production from GHG emissions. Hobbs then compared this mechanism to a source-based mechanism and found that if the default emission rate for all load is set equal to the target level of GHG emissions, this mechanism reduces to a source-based system which gives away emissions allowances to producers in proportion to their MWh of production. A higher value of the default emissions level implies that the TEAC mechanism is equivalent to a consumption-based tax on electricity and a source-based trading mechanism. Hobbs then briefly described results from his research on emissions permit allocation mechanisms and concluded from this research that care should be taken not to allocate permits in a manner that changes the incentive faced by future investors. For example, Hobbs noted that awarding investors in new generation units GHG permits in proportion to the expected emissions from the new unit creates incentives to invest in dirtier facilities.

These presentations were followed by questions from stakeholders and MSC members on implementation details and the administrative costs associated with the TEAC mechanism. Frank Wolak then adjourned the meeting at approximately 5:00 pm.