California Independent
System Operator Corporation

# Memorandum

**To:** ISO Board of Governors

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

**cc:** ISO Officers

**Date:** August 31, 2006

**Re:** ***Summary of the Market Surveillance Committee Meeting of August 8, 2006***

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

The Market Surveillance Committee (MSC) held a public meeting on August 8, 2006, at the California Public Utilities Commission at 505 Van Ness Avenue in San Francisco. All MSC members were present. Frank Wolak called the meeting to order and asked for public comment.

## Public Comment

There were no public comments at this time.

## Transmission for Renewable Generation

**Greg Cook**, Manager of Regulatory Affairs and Policy Development, gave a presentation on a proposal to establish a third category of transmission expansion projects specifically for renewable generation. Currently the ISO has two types of transmission expansion projects: (1) network facilities and (2) generation intertie (gen-tie) facilities. Network facilities are part of the looped transmission network and typically benefit more than one generation owner and are therefore paid for by the Participating Transmission Owner (PTO) and recovered through the ISO's Transmission Access Charge (TAC). Gen-tie facilities serve one generation unit owner, are typically less than 5 miles long, and power flows over them in one direction. For these reasons gen-tie facilties only benefit the generation unit owner interconnecting to the ISO control area so they are paid for by that entity. Cook noted that the ISO is considering creating a third category of transmission facilities that share many of the characteristics of gen-tie facilities, because they interconnect renewable generation facilities. The ISO proposal includes the carrying cost of these facilities in the TAC, rather than assign all of the costs to the renewable generation facilities. Cook concluded that the ISO plans to produce a second white paper on this issue in the near future.

During and following Cook's presentation there were questions by MSC members and stakeholders about the ISO's logic for establishing this third category of transmission expansion projects. Several MSC members questioned whether there was market failure that would be corrected by establishing this category of transmission projects. They found it difficult to distinguish this proposal from an explicit subsidy to renewable generation projects, because a similarly situated non-renewable generation unit owner would have to bear the full cost of constructing the transmission facilities necessary to interconnect to the ISO control area, whereas the renewable generation unit owner would have a portion of these costs paid by the TAC. These MSC members felt that from the perspective of ensuring a level playing field between renewable and non-renewable generation facilities, the cost of the transmission expansion necessary to interconnect renewable generation units should be included in the cost of the renewable generation unit, because the cost of interconnecting a non-renewable generation unit is included in its entry costs under the ISO's current interconnection policy. Several stakeholders agreed with this logic and elaborated on this point. **Sue Mara** of RTO Advisors felt that this proposal could have anti-competitive effects on retail competition because several PTOs are also load-serving entities (LSEs) and could have the transmission lines the renewable generation units needed to meet their renewable portfolio standard (RPS) included in the TAC, whereas other LSEs that are not PTOs would find this more difficult to do. **Tony Braun** of the California Municipal Utilities Association stated that the ISO was involving itself in integrated resource planning and this proposal would skew investment choices in favor of renewable generation units that could take advantage of this category of transmission expansions. **Anjali Sheffrin** responded that this proposal is designed to address: (1) the high cost of the transmission interconnection compared to the cost of the typical renewable generation project, (2) the relatively larger transaction costs associated with developing renewable projects because of the longer time necessary to site and construct these facilities, and (3) the efficiency of building a gen-tie facility to access a region with substantial renewable generation potential rather than develop renewable resources in piecemeal manner. She also noted that consideration of integrated planning was already part of the ISO's mission in planning the transmission grid.

There were also questions raised about how the project cost would be shared among renewable generation owners and the relevant PTO. The proposal Cook presented discussed having the renewable generation unit owner pay its capacity share ratio (the ratio of its capacity divided by the total renewable capacity interconnected to the line) of the going forward costs of the project. However, there appeared to considerable disagreement among members of the audience over what the term "going forward costs of the project" meant. Another question concerned how generation facilities would qualify for this third category of treatment. The proposal would rely on the California Energy Commission (CEC) to make this designation. Specifically, any generation facility that the CEC designated as meeting the RPS would qualify for this third category for its gen-tie facilities.

Several MSC members offered amendments to the proposal. One member suggested that the PTO should be the payer of last resort for the project. Under this approach, all renewable generation unit owners would pay for the cost of this project, the PTO would only stand ready to cover any shortfall in revenues that existed because the line was underused. This outcome is most likely to occur if the planned renewable generation does not ultimately materialize. The argument given by Cook for the third category of transmission expansions is that renewable generation projects typically require gen-tie facilities that are a very long distance from the existing bulk transmission network and that the scale of each of these initial renewable generation projects is small relative to capacity of the transmission line best-suited to exploit all of the future potential renewable generation resources in an area. Consequently, from a least-cost planning perspective it may be best to construct a transmission line to inter-connect a renewable generation source that is much larger than the initial renewable generation capacity constructed by any one developer. Under this modified proposal, the PTO would cover cost, through the CAISO Transmission Access Charge (TAC), of the transmission line that is currently unused, but would then assign the capacity ratio share of this cost to subsequent renewable generation unit owners as they enter. Under this scheme, renewable generation unit owners would pay the full cost of these gen-tie facilities, but the PTO would cover these costs through the CAISO TAC for as long as there are insufficient renewable generation units to cover the entire cost of the gen-tie facilities constructed. The MSC discussed a modification to the CAISO proposal in which the full cost of the gen-tie facility would be paid by the renewable resource owners. Ultimately, the PTO would be liable for a portion of the costs of the project only if the renewable resource owners expected at the time the facility was constructed never materialized. Consider the following example. Suppose that a 100 MW capacity line is determined to be the least-cost gen-tie facility given the renewable generation potential at a location. This line would eventually be shared between three renewable generation projects, but only one of the projects will be put into service with the gen-tie facilities. The initial cost of the project is $100 million. It is anticipated that these costs will be shared between the three renewable generation owners. The initial renewable facility would only be liable for $33.3 million, or one-third of the initial cost. However, each of the two subsequent renewable entrants would be liable for $33.3 million. Until these two renewable projects entered, the PTO would cover these costs from the TAC, and if these two entrants never materialized the remaining $66.6 million for the project would be paid for by the TAC. The liability of the initial entrant remains at $33.3 million, because it only uses one-third of the capacity of the line. However, each of these new entrants would be required to pay the PTO the present value of $33.3 million at the time they enter. This proposal would avoid subsidizing renewable generation owners in general and the two renewable generation owners that enter later, because they must pay the same discounted present value for the gen-tie facility as the initial entrant.

The MSC also questioned why the ISO proposal for a third category of transmission expansion would not include a transmission line needed to interconnect a non-renewable generation unit based on the ISO's assessment of total generation potential in that geographic area. For example, one could imagine a region distant from the existing ISO transmission network where many natural gas-fired generation units would find it profitable to locate if there was sufficient transmission capacity available. Under these circumstances, the least cost gen-tie for the first natural gas-fired generation unit constructed would have a much greater capacity than that generation unit's capacity. Treatment under the third category of transmission expansions, modified as described in the previous paragraph, would seem to apply equally well to this case as well as to the case of a distant location with significant renewable generation capacity potential. Several MSC members asked the ISO staff to investigate the extent to which the existence of a large potential source of generation capacity distant from the existing ISO transmission network was only the case for renewable resources. **Anjali Sheffrin** noted that natural gas facilities had the opportunity to coordinate among themselves to fund the interconnection facility. However, MSC members questioned why it would be more difficult for owners of renewable generation to coordinate to construct an interconnection facility.

Several MSC members also questioned why the proposal would award transmission rights similar to the current existing transmission rights (ETCs) to the renewable generation owners given how much effort the ISO has devoted to transitioning its current ETCs to purely financial transmission rights. These MSC members argued that the ISO should award purely financial congestion revenue rights (CRRs) to the renewable generation unit owners. The prospect of very low, or even negative, nodal prices would cause these renewable generation unit owners to reduce their output if there was transmission congestion out of this renewable generation area. These MSC members saw no reason to award ETCs instead of purely financial CRRs to the renewable generation unit owners.

## Review of Summer Operational Issues

**Eric Hildebrandt** of the Department of Market Monitoring reviewed several aspects of the performance of ISO markets during the summer of 2006. The major topics dealt with in Hildebrandt's presentation were: (1) day-ahead scheduling versus actual and forecasted loads, the functioning of the current Resource Adequacy (RA) process, the Must-Offer Waiver (MOW) denial process, and the details of the market performance on the super peak load day of July 24, 2006.

Hildebrandt reported that day-ahead schedules for peak hours of the day were typically greater than 97% and less than 103% of actual load. He also noted that the day-ahead load forecasts submitted by the scheduling coordinators (SCs) pursuant to the requirements of Amendment 72 have been very accurate. The sum of these forecasts is typically less than the ISO's load forecast. This is due in part to the fact that the ISO's load forecast includes losses, but those submitted by the SCs do not. Hildebrandt also noted that the ISO load forecast tends to overestimate the daily peak load.

Hildebrandt stated that RA showings totaled approximately 53,000 MW in July of 2006. There were also high levels of day-ahead and hour-ahead scheduling of RA capacity, which he attributed to many RA capacity contracts being coupled with energy contracts. In addition, RA resources that received MOW denials often subsequently scheduled in the day-ahead and hour-ahead market. Quick start RA resources not committed in the day-ahead MOW process are still counted by the ISO in MOW decisions for non-quick start RA and non-RA units. Non-RA units were committed by the ISO through the MOW process in cases where reliability need could not be met by RA resources. Hildebrandt then discussed the three reasons for MOW denials: (1) system needs, (2) zonal needs, and (3) local needs. The vast majority of MOW denials for RA capacity during June and July were for zonal and local needs. Except for the period July 16 to 24, the vast majority MOW denials of non-RA capacity were for zonal and local needs. During the periods July 16 to 24 virtually all MOW denials of non-RA capacity were for system reasons.

In his detailed analysis of the super peak day of July 24, Hildebrandt showed that there was a high level of day-ahead and hour-ahead scheduling despite high day-ahead and hour-ahead bilateral prices. This high level of scheduling relative to final demand led to relatively modest hourly real-time prices because low levels of real-time dispatches were needed to meet system demand, although there were a few five-minute periods during July 24 when the price hit the $400/MWh bid cap. These prices occurred when real-time demand was very close to the total amount of 5-minute capacity available. The high levels of day-ahead and hour-ahead scheduling on July 24 also limited the amount of non-RA capacity issued MOW denials to approximately 1000 MW. There was a moderate level of Out-of-Market (OOM) purchases due primarily to a cut of intertie schedules right before the start of the real-time market. Hildebrandt also noted that there was bid insufficiency in the day-ahead ancillary services for July 24 during the peak hours of the day. This made it difficult for the ISO to meet its operating reserve requirements without calling on some interruptible loads. By declaring a Stage 2 emergency, the ISO was able to obtain approximately 800 MW in load reductions.

Hildebrandt's presentation stimulated discussions among MSC members and several of the stakeholders present. One MSC member asked how the ISO prepared load forecasts for extreme temperature conditions such as those that occurred during the late July heat wave given the very small number of previous observations on temperature and system loads the ISO has for these temperature levels. This MSC member stated that the performance of the ISO market on July 24 was a very positive statement in favor of the California Public Utilities Commission's (CPUC) current RA process. This experience argues in favor of fixing any remaining defects in the current RA process rather than engaging in an extensive overhaul to implement a capacity payment mechanism. The high levels of fixed-price forward contracts for energy coverage of final demand by the three investor-owned utilities (IOUs) enabled them to schedule virtually all of their actual consumption in the day-ahead and hour-ahead markets. This left an extremely small real-time market, which meant there was adequate competition among suppliers to meet the very small real-time demand, so there were few 5-minute periods when the price hit the $400/MWh bid cap.

Nevertheless, the need to rely on MOW denials of non-RA capacity and OOM calls concerned the MSC and several stakeholders. Limiting reliance on these non-market mechanisms will improve the current RA process. As part of this discussion, **Brian Theaker** of Williams asked for details on the criterion used by the ISO operators to make OOM purchases. He was concerned that the ISO operators relied on OOM purchases and MOW denials in order to obtain needed reserve products that the current ancillary service markets do not provide. Theaker noted that under the current ISO tariff unloaded generation capacity cannot be counted as operating reserves even though these generation units are typically available to provide additional energy in real-time. Theaker raised the more general question of whether there may be reliability requirements that the ISO operators may be adhering to that cause them to issue MOW denials to non-RA units and make OOM purchases instead of purchasing additional ancillary services. He expressed a preference for all ISO operating reserve requirements to be met by purchases from the ISO's ancillary service markets. If these markets do not provide the appropriate reserve product then the ISO should create additional ancillary services. One MSC member noted that the MSC has been a persistent supporter of incorporating all relevant operating requirements into the ISO's ancillary services procurement decisions. For example, if the ISO operators feel that more than 7 percent operating reserves are necessary during certain hours, they should have the freedom to procure this amount of reserves. If a 20-minute responsive reserve product is necessary, then a market for one should be created.

## Convergence Bidding

**Farrokh Rahimi**, Principal Market Engineer, discussed the ISO's progress on the design of a convergence or virtual bidding (VB) framework under the Market Redesign and Technology Upgrade (MRTU). The Federal Energy Regulatory Commission (FERC) ordered the ISO to implement VB in Release 1 of MRTU or come up with a schedule to implement it as soon as possible. On June 13, 2006, there was a tutorial for the ISO Board on VB. Following this, the ISO received no objections from stakeholders to implementing VB in principle. Disagreements appear to be over the timing and a number of implementation details, which Rahimi discussed in his presentation.

The major challenge of these implementation details is how to capture the market efficiency-enhancing benefits of virtual bidding while limiting the potential for economic harm that may result from virtual bidding. For example, implicit virtual bidding (IVB) is a form of virtual bidding that is possible under the current ISO market design. Under IVB, suppliers or loads purposely over- or under-schedule to take advantage of or cause differences between day-ahead and real-time prices.[1] One implementation detail is how to best prevent implicit virtual bidding. The consensus among MSC members was to require explicit identification of VBs relative to bids from actual physical generation units and loads. Penalties for deviations between final schedules and actual production or consumption should be limited to extreme deviations.

There was some disagreement among MSC members on the extent of spatial granularity in VBs that should be allowed. One recommendation was to match the spatial granularity of physical bids with the spatial granularity of virtual bids. Specifically, allowing virtual generation bids at the nodal level because generation units bid at the nodal level. But only allow virtual load bids at the LAP level because physical loads are only allowed to bid at the LAP level. Another MSC member favored allowing virtual bidding at the nodal levels for both generation and load bids with a limit on the total MWs of VBs that the market participant can submit within a given hour.

Another issue concerned what load distribution factors would be used to clear virtual bids. Consistent with the first proposal in the previous paragraph, the consensus MSC recommendation was to use the same distribution factors that physical resources were cleared at in the day-ahead and real-time markets. This would typically imply different distribution factors for the day-ahead and real-time markets.

Other important implementation details discussed by the MSC were market power mitigation mechanisms and ancillary services cost allocation mechanisms. The MSC did not see the need to subject virtual bids to the ISO's market power mitigation mechanisms. These concerns were thought to be best addressed through position limits on the total MWs of virtual bids submitted within a given time period and/or on credit and collateral limits on the magnitude of virtual positions that market participants can take. The MSC felt that virtual transactions should be treated the same as physical transactions in allocating the integrated forward market (IFM), residual unit commitment (RUC) and ancillary services costs.

## Tradable Capacity Products and Capacity Markets

This segment of the meeting had three separate presentations relating to the ongoing RA process in California. First, **Mike Jaske** of the California Energy Commission briefed the MSC on the progress of the CPUC proceedings. Jaske

[1] Under the current California market design, there is no formal day-ahead energy market operated by the ISO but arbitrage is possible between day-ahead inter-tie congestion prices and real-time prices.

noted that the most recent CPUC decision clarified its desire for a tradable, standardized capacity product and authorized trading of this product on bulletin boards and exchanges.

**Phillip Muller** on behalf of the Capacity Market Advocate Group (CMAG) gave a presentation in favor of establishing centralized capacity market in California. Muller presented the consensus issues for the CMAG. These included a capacity requirement established and publicly stated years in advance, separate capacity requirements for transmission constrained and non-transmission constrained locations, administration of the capacity market by an independent entity such as the California ISO, and procedures to allow imports and dispatchable demand resources to meet the capacity requirement. He then discussed the remaining open issues. The major issues are: (1) how far ahead the capacity requirement must be met, (2) whether to use a downward sloping administrative “demand curve” to determine the market price of capacity, (3) whether to have an energy rent offset, and (4) whether to have performance incentives and how to structure them if they exist.

**Curtis Kebler** of Goldman Sachs made a presentation on behalf of the Bilateral Trading Group (BTG) expressing serious concerns with “proposals calling for the adoption of an eastern-style, centralized capacity market for California.” On behalf of BTG, Kebler encouraged the CPUC to examine comprehensively the costs and benefits of alternative resource adequacy mechanisms. He then outlined an alternative resource adequacy mechanism. The BTG favors a market where “consumption and investment decisions are driven by robust energy price signals.” The BTG also favors forward contracts for energy as the primary mechanism for protecting consumers from the potential exercise of market power in the short-term energy market and to support the financing of new generation sources. Capacity payments should be determined bilaterally and viewed only as supplemental revenues targeted to specific generation units because of special circumstances. Kebler then expressed many of the BTG’s concerns with a long-term capacity market.

These presentations stimulated a wide-ranging discussion of the appropriate long-term resource adequacy mechanism for California. On numerous occasions in the past, MSC members have expressed their concerns with a capacity payment mechanism for California. One MSC member noted that the experience during the late July heat wave with the existing CPUC resource adequacy process based on long-term energy contracting strongly supports continuing with this approach to resource adequacy. This MSC member also noted that because a significant fraction of energy in the Western Electricity Coordinating Council (WECC) comes from hydroelectric sources, energy shortfalls rather than capacity shortfalls are more important to guard against. This is different from the Eastern markets, which have a much smaller hydroelectric energy share. An additional difference from the Eastern markets that favors a long-term energy contracting approach for resource adequacy is the fact that California imports more than 20 percent of its energy consumption and it is impossible to specify which generation unit outside of California is actually providing energy to the California market. In contrast, the Eastern markets import very little net energy on an annual basis. All of these factors argue against a capacity-based resource adequacy process for California.

Discussion among the MSC members and stakeholders led to several broad recommendations if California did establish a capacity-based resource adequacy process. The first recommendation is to establish the capacity product as an option for the buyer to receive a refund if energy prices at some location exceed a previously agreed upon level. A supplier selling 1 MW of capacity is responsible for refunding the positive difference between the day-ahead, hour-ahead or real-time price and a pre-specified strike price. This responsibility should be for all hours of the year and the strike price should be set at some rather high level, between say $250/MWh and $400/MWh. Areas of the ISO control area should be divided into those where entry of new generation is feasible and those where it is not. There should be limited price mitigation beyond some damage control maximum price for this capacity product in areas that are not entry constrained. In entry-constrained areas there should be an administrative process for setting the price of the capacity product. To minimize the opportunities for existing generation unit owners to exercise market power in this market, procurement of this product should take place more than 2 years in advance of delivery. To satisfy the reliability needs of the ISO operators, this capacity contract must become physical in the sense that the ISO operators must know what physical generation resource will be used to hedge the risk of this capacity contract. The MSC favors delaying this physical showing as long as possible to give the seller of capacity contract the greatest flexibility to hedge this obligation.

## Demand Response

**Bruce Kaneshiro** of the CPUC and **David Hungerford** and **Pat McAuliffe** of the CEC updated the MSC on the progress of demand response programs in California. They broke down the various demand response program into two groups: (1) day-ahead and (2) day-of. The day-ahead programs are typically based on price incentives. These programs included critical peak pricing, demand-bidding programs, demand reserve partnership and the peak day 20/20 program. The day-of programs interrupt load based on ISO grid conditions. Specifically, these programs are triggered by the ISO declaring a Stage 2 emergency. Kaneshiro, Hungerford, and McAuliffe then presented information comparing the subscribed MWs for the various programs and the expected MWs based on the actual performance of the programs. For all three of the IOUs, the ratio of expected MW to subscribed MWs was significantly less than one. These ratios are significantly smaller for the day-of programs relative to the day-ahead programs.

Because the major goal of this presentation was to explore ways for the ISO to promote demand response programs, the remaining discussion focused on this issue. One MSC member noted that the ISO market is not a barrier to expanding the amount of demand response programs in California. By state law, the vast majority of demand in California is prohibited from paying a price that reflects the hourly wholesale price. Specifically, AB1-X prohibits customers of the three IOUs from paying a monthly bill that is higher than would be the case under the frozen retail rate. This law is a major barrier to active and effective demand-side participation. This requirement introduces substantial inefficiencies into the wholesale market because the amount of money collected from retail customers on an annual basis from this frozen retail rate must be sufficient to pay for annual wholesale energy costs, transmission costs, and distribution network costs. Retail customers pay the same price for each MWh they consume regardless of the cost of wholesale electricity during that hour. Consequently, the requirements of AB1-X do not protect customers from wholesale price volatility because they must still pay these volatile wholesale prices on an annual basis. Instead AB1-X prevents retail customers from lowering their annual bill by reducing their consumption during periods with high wholesale prices and shifting this consumption to hours with lower wholesale prices. This substitution of consumption across hours within the day or week provides significant reliability benefits as well. Consequently, AB1-X also degrades system reliability relative to a pricing mechanism that allows customers to benefit from paying a retail price that varies with the hourly wholesale price. Consequently, a necessary first step to active demand-side participation in the wholesale market is allowing all customers to benefit from paying retail price that varies with the hourly wholesale price.

Several MSC members asked whether any analysis had been done to determine if the benefits of the existing demand response programs were greater than their costs. Because many of these programs pay customers to reduce their demand during certain time periods, it is important to determine if the amount of money paid to these customers is less than the amount of money the load-serving entity saves from reducing its withdrawals from the transmission network. The level of the bid cap on the ISO's real-time energy market can have an enormous impact on the financial viability of demand response programs. Reducing total withdrawals by 1 MWh when the wholesale price is $1000/MWh saves the retailer $1000 in purchase costs. This same reduction when the price is $250/MWh is only $250/MWh. This fact points out another downside of a capacity-based resource adequacy mechanism. These mechanisms typically limit volatility of wholesale prices, which significantly reduces the likelihood that demand-response programs will pass the economic benefits versus costs test.

A second barrier to demand response programs is the availability of hourly meters for residential customers. The CPUC's recent decision to allow Pacific Gas and Electric to install hourly meters for all residential customers is a positive step towards addressing this problem. However, unless the CPUC adopts a default retail tariff for all customers that passes through the hourly wholesale price in the hourly retail rate that customer faces, it is unlikely that active demand-side participation in the wholesale market will materialize. As was graphically demonstrated during the period of June 2000 to June 2001, the option to return to a frozen retail rate provides incentives for customers to switch to this frozen default rate rather than reduce their demand during periods of high wholesale prices.

The MSC expressed hope that the CPUC would revise its default rate as soon as an hourly meter was in place for that customer. It makes no economic sense to go to the expense of installing an hourly meter for a retail customer and then not implementing a retail price that passes through the hourly wholesale price. Making this change in the default retail rate all customers pay would stimulate much-needed and effective demand-side participation in the wholesale market.

The meeting was adjourned by Frank Wolak at 5:15 pm.