ALSTON&BIRD LLP

601 Pennsylvania Avenue, N.W.
North Building, 10th Floor
Washington, DC 20004-2601

202-756-3300
Fax: 202-756-3333

Michael Kunselman   Direct Dial: 202-756-3395   Email: Michael.Kunselman@alston.com

September 22, 2005

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Amendment No. 72 to the CAISO Tariff
Docket No. ER05-___

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Sections 35.11 and 35.13 of the regulations of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 35.11, 35.13, the California Independent System Operator Corporation ("CAISO")[1] respectfully submits for filing an original and five copies of an amendment to the CAISO Tariff ("Amendment No. 72"). Amendment No. 72 would modify the CAISO Tariff to require Scheduling Coordinators ("SCs") to submit Day-Ahead Schedules that reflect 95% of their forecasted daily Demand. Amendment No. 72 would also require Scheduling Coordinators to provide to the CAISO on a weekly basis data regarding their actual daily loads, and would modify Section 20.3 to provide that the CAISO will keep this data confidential.

The CAISO requests that these tariff revisions be made effective as of the day after the date of this filing (*i.e.*, September 23, 2005), so as to address increased reliability concerns and costs associated with the high demand levels encountered during the late summer and early fall seasons.

---

[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, CAISO Tariff Appendix A, as filed August 15, 1997, and subsequently revised.

I. THE PROPOSED AMENDMENTS

The modifications to the CAISO Tariff that the CAISO proposes herein have been approved by the CAISO Board of Governors.[2] These Tariff changes are designed to reduce underscheduling and, as such, to enhance the reliability of the CAISO grid and to reduce Minimum Load Compensation Costs ("MLCC"), which are incurred as a result of Scheduling Coordinators submitting Day-Ahead schedules that do not meet forecasted Demand in the CAISO Control Area.

A. Background and Basis for Tariff Amendment

The CAISO Tariff does not currently require that Scheduling Coordinators submit schedules representing a certain minimum percentage of their daily Demand requirements. However, the CAISO's market design was premised on and designed with the expectation that most of the daily load in the CAISO Control Area would be scheduled against sufficient supply to serve that load in the Day-Ahead timeframe. Although the CAISO operates markets for Hour-Ahead and Real-Time energy, these markets were primarily intended to ensure that energy was available to meet unanticipated changes in load and resources. The Real-Time balancing market was designed to accommodate approximately five percent of the total forecasted load in the CAISO Control Area.

During the summer and fall of 2000, underscheduling, *i.e.*, the scheduling of significantly less load than forecasted, became a concern in the CAISO Control Area. As a result, in its December 15, 2000 "Order Directing Remedies for California Wholesale Electric Markets," 93 FERC ¶ 61,294 (2000), the Commission established, effective January 1, 2001, a requirement that Scheduling Coordinators schedule at least 95 percent of their load prior to Real-Time. The Commission also imposed a penalty charge of two times the cost of energy not to exceed $100/MWh for deviations in scheduling in excess of five percent of an entity's total hourly load requirements. However, in its December 19, 2001 "Order on Clarification and Rehearing," 97 FERC ¶ 61,275 (2001), the Commission revoked the 95 percent scheduling requirement and associated penalty effective retroactively to January 1, 2001. The Commission explained that the suspension of operation of the day-ahead and hour-ahead markets operated by the California Power Exchange, and the slow development of other markets to fill this void, had limited the ability and flexibility of loads to fill their requirements for energy in the day-ahead and hour-ahead timeframes. The Commission noted, however, that it would not hesitate to impose a similar

---

[2] A copy of the Board memorandum regarding "Approval for Proposed Tariff To Improve Day-Ahead Forecasting And Scheduling Practices," dated September 2, 2005, is attached hereto as Attachment A.

scheduling requirement in the future if underscheduling was to again create a reliability problem in California.

The CAISO is now proposing to institute a Tariff requirement that SCs schedule 95% of their forecast Demand in the Day-Ahead timeframe. The CAISO is doing so because the CAISO has observed an increased amount of load underscheduling behavior,[3] and the CAISO's current market structure is ill-equipped to address the problems that result from underscheduling. In particular, the CAISO's market structure lacks a resource adequacy requirement, a centralized forward energy market, and a formal unit commitment process. Ultimately, the implementation of resource adequacy requirements, currently under development by the California Public Utilities Commission, and the CAISO's Market Redesign and Technology Upgrade ("MRTU") will provide these key tools. However, until these market elements are implemented, the only reliability tools that the CAISO has to ensure that sufficient resources are committed and online in the necessary locations are the Must-Offer Obligation ("MOO") and Reliability Must-Run ("RMR") contracts.

Prior to making decisions concerning the commitment of units under the MOO, the CAISO must first evaluate the quantity and locational adequacy of the resources committed in Day-Ahead Schedules (except for resources with start-up times longer than approximately 18 hours), and decide whether such resources will be sufficient to ensure local, zonal, and system-wide reliability during each hour of the upcoming operating day. Under the CAISO's scheduling process, the CAISO has a very limited amount of time available to make these evaluations and, if necessary, take steps to ensure that additional resources are committed to meet forecasted load conditions. To the extent that Day-Ahead Schedules reflect load that is significantly less than forecasted load, the burden on CAISO operators to make commitment decisions in a short timeframe for resources not already scheduled, increases proportionally. Therefore, the risk that the reliability of the CAISO Controlled Grid will be negatively impacted increases as the number of commitment decisions the CAISO must make in the scheduling process increases.

In practice, the CAISO has found that when at least 95 percent of forecasted Demand is scheduled in the Day-Ahead timeframe, the number of commitment decisions and the task of ensuring that sufficient units are online in the appropriate locations are generally manageable. However, when Day-Ahead Schedules reflect less than 95 percent of forecasted load, the CAISO often finds itself in the position of having to commit as much as 4000 to 4500 MW of capacity in order to ensure reliability. This places a significant strain on CAISO operators to procure sufficient energy in the right locations to make up this shortfall. The burden placed on CAISO operators detracts from the ability of

---

3 *See* Attachment A at 1-2.

CAISO operators to react and respond effectively and efficiently to other reliability issues that might arise in the CAISO Control Area, thereby decreasing the ability of the CAISO to fulfill its primary mission of ensuring the reliability of the CAISO Controlled Grid.

In addition to the burden load underscheduling places on CAISO operations to ensure the commitment of sufficient resources, the failure of Day-Ahead schedules to accurately reflect forecasted load conditions also places the CAISO in the position of having to estimate what, if any, additional load might be scheduled in the Hour-Ahead Market. There is no precise way to estimate what additional load will be scheduled in the Hour-Ahead market. At times, the amount of load scheduled in the Hour-Ahead Market increases and at other times it decreases. If the CAISO underestimates the amount of incremental load scheduled in the Hour-Ahead timeframe, the CAISO could face a significant reliability issue due to insufficient resources being online to serve that load. However, if the CAISO over-estimates the quantity of incremental load scheduled in the Hour-Ahead timeframe, then the CAISO runs the financial risk of committing too many Must-Offer resources. From an operational and reliability perspective, the risk of underestimating the amount of incremental load appearing in the Hour-Ahead Market is much more significant than that of overestimating. Nevertheless, because of the requirement that the CAISO pay Minimum-Load Cost Compensation ("MLCC") to units committed under the MOO, there potentially can be a significant -- and unnecessary -- cost impact to CAISO Market Participants as a result of over-procuring resources because of the inaccuracy of Day-Ahead Schedules.

Moreover, until the CAISO's current zonal congestion management system is replaced by a nodal congestion management system as part of MRTU, the underscheduling of load decreases the ability of the CAISO to recognize potential congestion situations that may result in real time. This, in turn, results in an increased operational burden on the CAISO to relieve such congestion in real time. For instance, the CAISO has experienced situations in which there was no inter-zonal congestion in the Day-Ahead Market because of the lack of load scheduled in the Day-Ahead Market, and then observed significant congestion in real time. In these situations, the CAISO has been forced respond quickly to resolve this congestion in real time. If the total amount of load scheduled in the Day-Ahead represented a higher percentage of actual load, then the CAISO would have known in the Day-Ahead timeframe that schedules might be infeasible. This would allow the CAISO's congestion management system to take appropriate action in the case of inter-zonal congestion, or, in the case of intra-zonal congestion, provided the CAISO with some advance indication that it might need to undertake some mitigating action in order to prevent a real-time reliability problem.

Further, the CAISO believes that this Amendment will, generally, have a positive financial impact on CAISO Market Participants. Requiring SCs to schedule at least 95 percent of their forecast Demand will reduce the overall cost exposure to all Market Participants by reducing the amount of system-wide MLCC costs incurred as a result of fewer unit commitments made pursuant to the MOO. The CAISO acknowledges that there potentially could be an increase in costs for LSEs due to the potential foregone opportunity of acquiring cheaper Hour-Ahead supplies. However, the CAISO believes that any increased costs will be outweighed by the reliability benefits of the proposal.

The CAISO does not believe that the 95 percent scheduling requirement will be a burden on LSEs. Many LSEs have publicly stated that they have secured sufficient resources and or contracts to meet up to 115% of their peak load. Therefore, the CAISO believes that it is reasonable for parties who have publicly expressed supply sufficiency to be able to schedule at least 95 percent of their load in the Day-Ahead Market.

Finally, the CAISO believes that administrative rules such as those proposed herein can be eliminated upon implementation of the comprehensive MRTU market design. In that regard, MRTU will contain certain mechanisms (*e.g.*, the Residual Unit Commitment process) that will provide the appropriate incentives for LSEs to forward schedule their forecasted load. In addition, the Resource Adequacy requirement and the ability to procure energy in the Day-Ahead Market representing transmission constraints will help ensure the feasibility of Schedules prior to real time, and will provide the CAISO with the ability to commit sufficient resources in such a way so as to ensure reliability entering the Real Time Market.

B. Stakeholder Feedback on the Proposal

The present Tariff Amendment evolved out of a process by which the CAISO sought to secure from LSEs voluntary individual commitments to adhere to a 95 percent scheduling requirement. In that regard, on July 7, 2005, there was a meeting attended by representatives of the CAISO, the Commission and CAISO Market Participants to discuss the CAISO's need to maintain reliable grid operations in Southern California and minimize the CAISO's reliance on the MOO. There was a follow-up conference call on July 12, 2005 and a subsequent call on July 22, 2005.

Following conference calls with stakeholders, the CAISO sought to obtain commitments from LSEs, in the form of letter agreements, to schedule 95 percent of their forecast Demand in the Day-Ahead and to provide the CAISO with load forecast data and a weekly reconciliation of actual Demand and forecast Demand. The CAISO obtained the commitments of most LSEs in the

Control Area to cooperate in scheduling 95 percent of their forecast Demand in the Day-Ahead and provide the requested information to the CAISO. By the instant Tariff filing, the CAISO is essentially formalizing and codifying what was included in the letter agreements executed by the CAISO and LSEs.

As part of the aforementioned process, the CAISO had considerable opportunity to discuss the proposed scheduling requirement with LSEs and garner useful feedback. While there was significant discussion regarding the reporting and scheduling requirements, there was general support for the forecasting requirement. Some SCs expressed concern that it was redundant for them to provide a forecast when their schedules already represented their forecast, and they had no intent of scheduling less then 100 percent of their forecast in the Day-Ahead Market. While many stakeholders expressed support for a minimum scheduling requirement, some LSEs expressed concern that a 95 percent scheduling requirement in the Day-Ahead timeframe might increase their overall capacity and energy procurement costs. The Investor Owned Utilities, and in particular PG&E, expressed serious concern about the 95 percent scheduling requirement. PG&E maintained that this requirement will lead to higher costs for consumers because it will require PG&E to make financially binding decisions to acquire energy by the Day-Ahead that otherwise could be postponed to the Hour-Ahead at a lower price. In that regard, PG&E explained that it has CPUC-approved contracts that provide PG&E with intra-day flexibility and that PG&E relies on these contracts, in combination with its Day-Ahead resources, to submit fully resourced Schedules by the Hour-Ahead. PG&E argued that if it were to disregard these resources to increase its Day-Ahead resource scheduling, it would be inconsistent with the CPUC's least-cost dispatch requirement, needlessly drive up costs for PG&E's customers, and not improve the CAISO's ability to ensure that sufficient resources are available. PG&E offered an alternative to the CAISO's proposed 95 percent Day-Ahead scheduling requirement. Specifically, PG&E offered to provide a list of additional intra-day resources that PG&E has under contract which, when combined with the resources scheduled by PG&E in the Day-Ahead, would be able to meet 100 percent of PG&E's Day-Ahead forecast by the Hour-Ahead. PG&E stated that this approach would provide the CAISO with the necessary information to make reliability decisions, while at the same time maintaining PG&E's flexibility to procure energy supplies at least cost.

The CAISO acknowledges PG&E's concerns but believes that the proposed 95 percent scheduling requirement provides sufficient flexibility to PG&E. The CAISO is concerned that, although a listing of resources from LSEs may be helpful, it is not clear whether all the resources that an LSE lists will be made available to the CAISO via the normal bid stack or whether the CAISO would have to make special calls to actually obtain the energy from such resources. This could lead to a situation where there is significant underscheduling and the CAISO is simply left with a list of resources that the

CAISO may or may not be able to dispatch via its normal means for doing so. Also, the CAISO would need to be able to evaluate resource ramping and other unit constraints. Further, SCs may also want to include imports and trades as resources on the list, which raises the same concerns with respect to the CAISO's ability to call on these resources. The bottom line is that, while a single SC providing a list of resources that are available may be feasible, such a solution potentially could become operationally onerous if numerous LSEs were to underschedule in the Day-Ahead timeframe and simply provide a list of available resources. In any event, the CAISO will monitor the impact and benefits of the 95 percent scheduling requirement and will seek modifications to the requirement in the future if the CAISO finds that it is inappropriate under some conditions.

Furthermore, at least one LSE indicated that a requirement to schedule 95 percent in the Day-Ahead Market would impact its ability to provide needed Ancillary Services reserves to the system. The CAISO believes, however, that if a Market Participant has procured sufficient resources to meet its energy and reserve requirements, then their ability to provide both energy and Ancillary Services should not be an issue. Some LSEs also maintained that the 95 percent scheduling requirement will prevent them from making reasonable economic decisions to purchase some of their load in real time. The CAISO submits that a 95 percent Day-Ahead scheduling requirement is nevertheless reasonable, especially given that the CAISO's Real Time Market for energy was intended to be an imbalance market, not a market to procure energy to serve significant load obligations.[4]

Finally, some LSEs have stated that, while it is not their intent to underschedule in the Day-Ahead Market, they find it difficult to procure the necessary load shaping products in the Day-Ahead timeframe to meet their entire load in some peak hours. This may be the case currently. However, to the extent there is a demand for more refined load shaping products, the establishment of a 95 percent scheduling requirement may, in fact, encourage the development of such products.

---

[4] Although real-time prices in the CAISO Markets are consistently lower than bilateral price indices, one of the reasons real-time prices are depressed is the amount of Must-Offer and RMR energy the CAISO must-schedule in real time to make up for aggregate and locational Schedule deficiencies. As a result, the true prices for real-time energy are greater than what is indicated by real-time prices. Current price differentials do not constitute a sufficient reason to deviate from a 95 percent scheduling requirement even though the opportunity for LSEs to take advantage of the depressed real-time prices will be reduced.

C. Proposed Tariff Modifications

The primary modification proposed in this Amendment is the addition of new Section 2.2.7.2.1.1 to the CAISO Tariff. This section will require that Scheduling Coordinators submit to the CAISO, for each hour of each Trading Day, a Day-Ahead Schedule that includes at least 95 percent of a SC's aggregate forecast Demand.

Additionally, to help the CAISO make better informed and more timely choices regarding the commitment of units under the MOO and RMR contracts, the CAISO is also proposing, in a new Section 2.2.7.2.1.2 to the CAISO Tariff, to require that SCs who submit Day-Ahead Schedules reflecting less than their entire forecast Demand for the peak hour of a Trading Day must also submit a list of resources that they plan to rely on during that Trading Day to meet their forecast peak Demand.

The CAISO also is proposing several new Tariff sections intended to assist the CAISO in identifying and curbing underscheduling practices. Although the CAISO is not proposing to implement discrete penalties associated with underscheduling, the CAISO believes that such behavior could constitute a violation of the data accuracy requirements of its Enforcement Protocol, and the CAISO is proposing several tariff modifications in order to assist it in identifying and addressing underscheduling. First, the CAISO proposes to add a new Section 2.2.12.3.2 to the CAISO Tariff that will require SCs to submit, each week, an hourly summary comparing their total estimated actual load with their forecasted load, and a new Section 2.2.12.3.3, which will require SCs to update their actual load estimates with final load data within 60 days of providing the weekly summaries required by Section 2.2.12.3.2. These requirements, along with the pre-existing Tariff obligation that SCs submit their daily Demand Forecasts to the CAISO -- which will now be reflected in Section 2.2.12.3.1 -- will greatly facilitate the CAISO's review of the accuracy of SCs' scheduling and load forecasting. Under new Section 2.2.18, the CAISO will routinely report to the Commission underscheduling behavior pursuant to its obligation to notify the Commission of any potential violation of certain ISO market rules in accordance with Section 8.2 of the Enforcement Protocol ("EP").

Finally, the CAISO is proposing to add to Section 20.3.2 a provision explicitly stating that data provided by SCs pursuant to Section 2.2.12.3 will be treated as confidential by the CAISO. Consistent with Section 20.3.4, the CAISO may provide such information to the Commission without first issuing a market notice if the Commission, or its staff, requests such information in the course of an investigation or otherwise. Also, under Section 8.2 of the CAISO's Enforcement Protocol, the CAISO will make referrals to the Commission of potential violations of the CAISO's Rules of Conduct as set forth in the

Enforcement Protocol, including, *inter alia,* underscheduling practices that might constitute violations of the CAISO's Rules of Conduct.

II. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

Charles F. Robinson
Anthony J. Ivancovich
The California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, California 95630
Tel: (916) 351-4400
Fax:(916) 608-7296

Sean A. Atkins
Michael Kunselman
Alston & Bird LLP
601 Pennsylvania Ave., N.W.
North Building, 10th Floor
Washington, DC 20004
Tel: (202) 756-3300
Fax: (202) 756-3333

III. EFFECTIVE DATE

The CAISO requests that the Commission grant a waiver of its Rules and approve the enclosed Tariff amendments effective as of the day after this filing, *i.e.,* September 23, 2005. The CAISO submits that waiver of the 60-day notice period is appropriate for several reasons. First, allowing these provisions to become immediately effective will help to address reliability concerns resulting from the high demand conditions that often occur during late summer and early fall. An earlier effective date also should result in the CAISO incurring fewer MLCC costs, for the reasons explained above, which in turn will result in an overall savings to CAISO Market Participants. Finally, a waiver of the 60-day notice period will not prejudice the affected LSEs because, as stated above, the CAISO has already engaged in extensive informal discussions with these entities concerning voluntary implementation of the provisions set forth in this Tariff amendment.

IV. SERVICE

The CAISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Service Agreements under the CAISO Tariff. In addition, the CAISO is posting this transmittal letter and all attachments on the CAISO Home Page.

V. ATTACHMENTS

The following documents, in addition to this letter, support this filing:

Attachment A	Board Memo Concerning Proposed Tariff Amendment to Improve Day-Ahead Forecasting and Scheduling Practices
Attachment B	Clean Tariff Sheets Incorporating the Amendment No. 72 Modifications Proposed Herein
Attachment C	Sheets Showing the Amendment No. 72 Proposed Modifications Blacklined Against the Existing CAISO Tariff

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger. Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

Sean A. Atkins
Michael Kunselman
Alston & Bird LLP
601 Pennsylvania Ave., NW
North Building, 10th Floor
Washington, DC 20004
Tel: (202) 756-3300
Fax: (202) 756-3333

Charles F. Robinson
General Counsel
Anthony J. Ivancovich
Assistant General Counsel, Regulatory
The California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296

ATTACHMENT A

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Operations Committee

From: Mark Rothleder, Principal Market Developer

cc: ISO Board of Governors, ISO Officers

Date: September 2, 2005

Re: ***Approval for Proposed Tariff to Improve Day-Ahead Forecasting and Scheduling Practices***

This memorandum requires Board action.

EXECUTIVE SUMMARY

This year the CAISO (ISO) began to experience increased occurrences in which the total quantity of load scheduled in the Day-Ahead market was significantly less then ISO forecasted load and ultimately actual metered load. Early into the summer, concerns regarding the impact such scheduling behavior could have this summer when supply conditions were forecasted to be tight especially in Southern California had prompted the ISO and the Federal Energy Regulatory Commission (FERC) to take action to reduce the level of under scheduling.

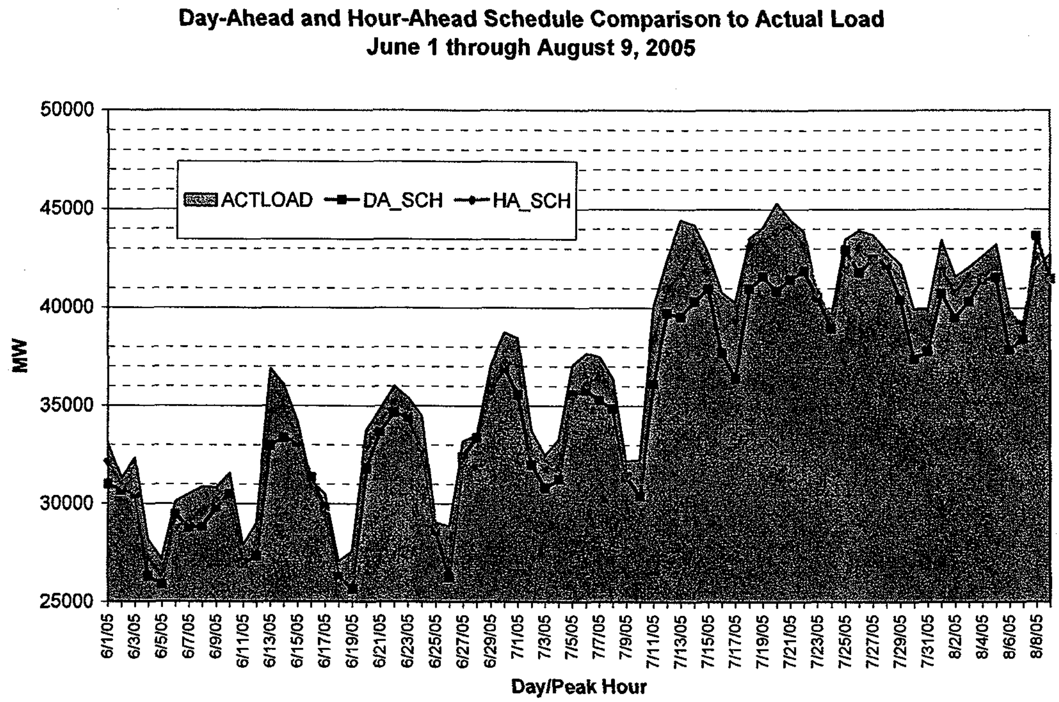
On July 7, 2005, the Federal Energy Regulatory Commission convened a conference to discuss issues related to maintaining reliable system operations in Southern California for Summer 2005. One of the topics discussed at the conference was the impacts and proposed resolutions to the under scheduled load in the Day-Ahead market.

At the conference, the consensus among the parties was to support the concept of a demonstration that day ahead schedules were in line with the peak load forecast for that day. As a result of the conference, the ISO undertook immediate short-term steps including the development of a Memorandum of Understanding (MOU) between the ISO and Scheduling Coordinators that would: 1) establish a minimum Day-Ahead scheduling benchmark of 95% of forecasted load for Scheduling Coordinators representing Load Serving Entities to schedule in the Day-Ahead market 2) better identify the source and magnitude of under scheduled load and resources and 3) provide ISO additional information to improve Must-Offer decisions the ISO must make when insufficient resources are scheduled to meet the load in the Day-Ahead market. While attempting to secure acceptance of the MOU, several parties indicated that the MOU must be replaced by actual tariff modifications to ensure uniform application of the new requirements and to provide necessary assurance of regulatory cost recovery for compliance with the new Day-Ahead scheduling requirements.

On July 15, 2005, the ISO issued a final version of MOU. As of August 23, 2005, the majority of Scheduling Coordinators representing Load Serving Entities has signed the MOU and has started to implement the actions identified in the MOU. The ISO continues work with Scheduling Coordinators to execute the following specific measures of the agreement: Recent analysis indicates the level of deviation between Day-Ahead scheduled load and actual has decreased since issuance of the MOU (Figure 1). A more comprehensive assessment of load scheduling practices before and after the MOU is provided in a separate report prepared by the Department of Market Monitoring (DMM Report). This report is included as an attachment to the regular Market Monitoring Board Report.

151 Blue Ravine Road
Folsom, California 95630
(916) 351-4400

Figure 1



The ISO is not requesting penalties at this time for non-compliance with the proposed Day-Ahead scheduling requirement. Rather, the ISO believes it is more appropriate to monitor and share scheduling data with FERC in order to gain a better understanding as the source and impact of under scheduling. Based on this monitoring and analysis, the ISO may propose modification to the scheduling requirement including potential penalties structure sometime in the future. Furthermore the monitoring and impact analysis may lead to refinement that may indicate greater scheduling latitude is appropriate. Nonetheless, at this time the ISO strongly believes it is appropriate to set the Day-Ahead minimum scheduling requirement to 95% of a Scheduling Coordinators forecast load with after the fact reconciliation of schedules to actual load.

In its own independent assessment of load scheduling practices (DMM Report), the Department of Market Monitoring noted that levels of Day-Ahead scheduling improved significantly since the MOU was implemented and recommended the following actions:

- The ISO should seek to change the current method for allocating unit commitment costs under the Must Offer Waiver Process associated with meeting shortfalls in Day-Ahead load scheduling so that these costs are allocated to load that is under scheduled in the Day-Ahead as opposed to the current method of allocating it to load that is under scheduled in the Hour-Ahead;
- The ISO should provide a near real-time index of the Must Offer Waiver Denial costs associated with under scheduled load so that LSEs have a better sense of the actual costs of purchasing energy in real-time;
- The ISO should monitor and report levels of under scheduling by Scheduling Coordinator to FERC's Office of Market Oversight and Investigation; and
- The ISO should work with the CPUC to provide assurances to the UDCs for recovery of additional costs associated with complying with the MOU.

DMM believes that these actions would increase the level of load scheduling in the Day-Ahead market. While DMM does not oppose having the 95% scheduling requirement provisions of the MOU expressed in the ISO tariff, it notes that such a requirement may have the following undesirable consequences:

- May increase LSE procurement costs to the extent cheaper Hour-Ahead purchase opportunities are foregone in order to comply with the requirement;
- May lower the amount of self-provided ancillary services to the extent LSEs choose to schedule energy from these resources in order to comply with the requirement; and
- May exacerbate over-generation conditions during off-peak hours or in off-peak seasons (e.g., Spring).

DMM believes that the potential benefits a tariff imposed scheduling requirement would bring in terms of increased reliability should be weighed against these potential costs. The DMM Report also notes a number of significant implementation issues that would need to be addressed and incorporated into the tariff should the CAISO ultimately seek to impose financial penalties for violations of the scheduling requirement.

Since the MOU was intended to be an interim solution, the MOU is scheduled to sunset on October 1, 2005. Based on follow-up discussions with FERC staff, the ISO believes the measures identified in the MOU should be an explicit obligation expressed in tariff provisions. As a result, the ISO management now requests authorization to file necessary to tariff language that follows the scheduling and reporting responsibilities of a Scheduling Coordinator representing a Load Serving Entities identified in the MOU. It is important to note that reducing or eliminating the system-wide under scheduling does not in of itself resolve local schedule feasibility issues that result in the ISO needing to commit Must-Offer resources for local or zonal conditions.

MOVED,

That the ISO Board of Governors authorizes ISO Management to file a Tariff amendment at FERC to establish a Day-Ahead market scheduling requirement for Scheduling Coordinators to schedule at least 95% of their forecasted load, and a reporting requirement for Scheduling Coordinators to provide the ISO a daily load forecast prior to submitting daily load schedules and actual or estimated actual load on a weekly basis for all trade days in the preceding week.

BACKGROUND

While the ISO market design never explicitly required a minimum load-scheduling requirement, the expectation was that most load would be scheduled prior to real-time, leaving the real-time market to be a small imbalance only market. At various times, the 95% scheduling threshold was used as an appropriate level of load schedule prior to real-time market. After the energy crisis of 2000, the FERC did establish a minimum scheduling requirement of 95% with the imposition of penalties for not meeting this requirement. However, due to concerns such a penalty requirement would have on market power at the time, FERC removed penalties but left the possibility of re-imposing penalties if under scheduling became an issue again.

The current ISO market structure lacks a resource adequacy requirement, a centralized forward energy market and lacks a no formal unit commitment process. Ultimately, CPUC rulemaking on resource adequacy and the Market Redesign and Technology Upgrade (MRTU) is intended to eliminate these deficiencies. However, until these market elements exist, the only reliability tools the ISO has to ensure enough resources are online in the right place is Must-Offer (MOO) and Reliability Must Run (RMR). Except for resources with start-up times longer than approximately 18 hours, prior to making decisions on Must-Offer the ISO must first evaluate the quantity and adequacy Day-Ahead schedules has towards meeting local, zonal and system wide reliability. In making the evaluation the ISO has a very limited time to make reliability decisions regarding what and where must-offer resources are needed to be online. To the extent Scheduling Coordinators' schedules fall significantly short of forecasted load, the burden, on ISO operators to make commitment decisions regarding resources not already scheduled, increases significantly. Therefore, risk of impacting reliability increases as the number of commitment decisions late in process increases. In practice when 95% is schedule in the Day-Ahead market the amount of commitment decision and the risk of not getting all resources online is generally manageable. However, when the under scheduling approaches or surpasses 90%, the ISO is in the position of having to commit potentially as much as 4000 – 4500 MW of capacity to ensure reliability.

In addition to the burden put on the ISO operations when significant under scheduling occurs, the ISO is put in the position of having to estimate what if any additional energy is going to be provided in the Hour-Ahead market. There is no precise way to estimate what if any additional load will be scheduled in the Hour-Ahead market. At times the level of load scheduled in the Hour-Ahead increases and at other times decreases. If the ISO over-estimates the amount incremental load scheduled in the Hour-Ahead, the ISO could face a significant reliability issue due to insufficient resources being online. However, if the ISO under-estimates the quantity of incremental load scheduled in the Day-Ahead, the ISO runs the financial risk committing too many Must-Offer resources. From an operational perspective, the impact of over-estimating is much more significant than under-estimating. Nonetheless, less load and resource scheduled Day-Ahead increases the amount of load that the ISO has to estimate when making Day-Ahead Must-Offer waiver decisions.

Load Serving Entities have publicly expressed that they have secured sufficient resources and or contracts such as Firm LD contracts to meet up to 115% of their peak load. It is reasonable to expect that entities that rely heavily on such LD contracts would have to schedule in the Day-Ahead in order to exercise these contracts and meet the 95% requirement. At the July 7, 2005 conference the ISO understood that some Load Serving Entities have relied as much as 100% on the such LD contracts. Therefore if such contracts are not scheduled Day-Ahead the implication is that the LSE is going to have to rely on the ISO's ability to commit resources under Must-Offer and/or rely on the real-time imbalance market.

Lastly, until MRTU and the current zonal congestion management system is replaced by a Locational congestion management system, the less load that is scheduled in the Day-Ahead market the greater the chance that congestion situations may result in a greater burden in real-time to relieve such congestion. The ISO has experienced situations in which inter-zonal congestion was not observed in Day-Ahead market due to the lack of load scheduled in the Day-Ahead market and moved into real-time experiencing significant congestion. Had the total amount of load scheduled represented a higher percentage of the actual load, the ISO would have known in the Day-Ahead time frame that schedules might be infeasible.

STAKEHOLDER FEEDBACK

While many stakeholders have expressed support for a minimum scheduling requirement, some Load Serving Entities have expressed concern that a 95% scheduling requirement in the Day-Ahead may increase their overall cost of capacity and energy procurement. Furthermore at least one Load Serving Entity indicated that a requirement to schedule 95% in the Day-Ahead market would impact their ability to provide needed A/S reserves to the system. Some go further to express that it is unreasonable to prevent market participants from making reasonable economic decisions to purchase some of their load in the real-time, especially when the ISO real-time prices are on average depressed relative to forward energy price indices. The reason some of the real-time energy prices are depressed is in part due to the amount of energy produced from ISO call on resources through Must-Offer and RMR resources in real-time that was not scheduled or produced in the Day-Ahead market.

Some Load Serving Entities have expressed that while it is not their intent to under schedule in the Day-Ahead market they find it difficult to find the necessary load shaping products in the Day-Ahead time frame to meet their entire load in during some peak hours. This may be true. However, to the extent there is demand for more refined load shaping products, there may be suppliers willing to provide such products. Therefore, establishing a 95% scheduling requirement may in fact encourage such products to develop.

Concerns have been expressed regarding the ISO load forecast and its tendency to over-forecast. The ISO recognized this problem in mid July and has taken steps to correct the day-ahead forecasting errors. Over the June and July period, ISO day-ahead forecasts were on average 1.5% higher than actual load during the peak hour of each day. However, on several days in late June and mid July, the day-ahead forecast was incorrect approximately 4 to 5 percent, or up to 2,300 MW, in part due to unexpected weather conditions along the California coast. However, much of the day ahead over-forecasting during this period was traced to the inclusion of a load spike predictor algorithm that was developed by the ISO to address under-forecasting of load in previous years during warming trends. Once the ISO's over-forecasting problem was recognized in early July, several steps were taken to improve the forecast including:

Pacific Gas and Electric requested that the 95% scheduling requirement be relaxed and instead be augmented with a list of resources the Scheduling Coordinator intends to make available to meet its full forecasted peak load. The ISO feels that this approach may be workable. However, the extent to which this alternative is acceptable is dependent on the timing and number of such resource lists and the level to which the ISO has ability to actually call on such resources. At this time, the ISO recommends that the usefulness of such a list be evaluated by maintaining the 95% scheduling requirement but have Scheduling Coordinators submit such an augmented list to the extent they do not schedule their entire forecast in the Day-Ahead market.

CONCLUSION

ISO Management requests authorization to file necessary to tariff language that follows the scheduling and reporting responsibilities of a Scheduling Coordinator representing a Load Serving Entities identified in the MOU.

MOVED,

That the ISO Board of Governors authorizes ISO Management to file a Tariff amendment at FERC to establish a Day-Ahead market scheduling requirement for Scheduling Coordinators to schedule at least 95% of their forecasted load, and a reporting requirement for Scheduling Coordinators to provide the ISO a daily load forecast prior to submitting daily load schedules and actual or estimated actual load on a weekly basis for all trade days in the preceding week.

ATTACHMENT B

2.2.7.2 Submitting Balanced Schedules. A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate forecast Demand with respect to all entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline.

2.2.7.2.1 Submission of Schedules Sufficient to Meet Forecasted Demand

2.2.7.2.1.1 Each Scheduling Coordinator shall submit to the ISO, for each hour of each Trading Day, a Day-Ahead Schedule that includes at least ninety-five percent (95%) of that Scheduling Coordinator's forecast Demand for each hour, for each UDC Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC Service Areas.

2.2.7.2.1.2 To the extent that a Scheduling Coordinator submits a Day-Ahead Schedule that reflects less than one hundred percent (100%) of its entire forecast Demand for the peak hour of that Trading Day in each applicable UDC Service Area, as set forth in Section 2.2.7.2.1.1, that Scheduling Coordinator must submit, along with its Day-Ahead Schedule, a list of the resources that the Scheduling Coordinator plans to rely upon during that Trading Day to meet its forecast peak Demand requirement.

2.2.7.3 Limitation on Trading. A Scheduling Coordinator, UDC or MSS that does not maintain an Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, shall maintain security in accordance with Section 2.2.3.2. For the avoidance of doubt, the ISO Security Amount is intended to cover the entity's outstanding and estimated liability for either (i) Grid Management Charge; and/or (ii) Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, High Voltage Access Charge, Transition Charge, Usage Charges, and FERC Annual Charges. Each Scheduling Coordinator, UDC or MSS required to provide an ISO Security Amount under Section 2.2.3.2 shall notify the ISO of the initial ISO Security Amount (separated into amounts securing payment of the Grid Management Charge and amounts securing payments of other charges) that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such ISO Security Amount prior to the date the Scheduling Coordinator commences trading or the UDC or MSS commences receiving bills for the High Voltage

2.2.12.3 Demand Information.

2.2.12.3.1 Daily Information. By 10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

2.2.12.3.2 Preliminary Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than seven (7) days after the end of each week, which shall end at Sunday HE 24, data for the previous week (Monday through Sunday), in electronic format, comparing, for each hour of that week: (1) the Scheduling Coordinator's total Day-Ahead scheduled Demand by UDC Service Area, as submitted pursuant to Section 2.2.7.2, (2) the Scheduling Coordinator's total Day-Ahead Demand Forecast by UDC Service Area, as submitted pursuant to Section 2.2.12.3.1, and (3) an estimate of the Scheduling Coordinator's actual Demand by UDC Service Area.

2.2.12.3.3 Final Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than 60 days after the date for the submission of preliminary weekly data pursuant to Section 2.2.12.3.2, updated data in the exact same format as required in Section 2.2.12.3.2, reflecting the Scheduling Coordinator's total actual Demand by UDC Service Area for the applicable period.

2.2.12.4 The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.

2.2.12.5 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

2.2.12.6 ISO Analysis of Preferred Schedules. On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned

2.2.16 Relationship Between ISO and Participating Loads

The ISO shall only accept bids for Supplemental Energy or Ancillary Services, or Schedules for self-provision of Ancillary Services, from Loads if such Loads are Participating Loads which meet standards adopted by the ISO and published on the ISO Home Page. The ISO shall not schedule Energy or Ancillary Services from a Participating Load other than through a Scheduling Coordinator.

2.2.17 Relationship Between ISO and Eligible Intermittent Resources and Between the ISO and Participating Intermittent Resources

The ISO shall not schedule Energy from an Eligible Intermittent Resource other than through a Scheduling Coordinator. Settlement with Participating Intermittent Resources that meet the scheduling obligations established in the ISO Protocols shall be as provided in this ISO Tariff. No Adjustment Bids or Supplemental Energy bids may be submitted on behalf of Participating Intermittent Resources. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Adjustment Bids or Supplemental Energy bids are submitted, or that fails to meet the scheduling obligations established in the ISO Protocols, shall be scheduled and settled as a Generating Unit for the associated Settlement Periods (except that the Forecasting Fee shall apply in such Settlement Periods).

2.2.18 Compliance with Scheduling and Data Provision Requirements. Pursuant to its obligation to notify FERC of any potential violations of Section 7 of the ISO's Enforcement Protocol, the ISO will routinely report any underscheduling behavior that it observes to FERC, for investigation as a potential violation of Section 7 of the Enforcement Protocol and/or FERC's Market Behavior Rule 2.

2.3 System Operations under Normal and Emergency Operating Conditions.

2.3.1 ISO Control Center Operations.

2.3.1.1 ISO Control Center.

2.3.1.1.1 Establish ISO Control Center. The ISO shall establish a WECC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services.

20.3.2 Confidential Information

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator;

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Section 2.2.12.3.

20.3.3 Other Parties

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.3.2; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such confidential data or information relating to an individual Market Participant and provided, however, that the ISO may disclose information as provided for in its bylaws.

ATTACHMENT C

2.2.7.2 **Submitting Balanced Schedules.** A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate forecast Demand with respect to all entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline.

2.2.7.2.1 Submission of Schedules Sufficient to Meet Forecasted Demand

2.2.7.2.1.1 Each Scheduling Coordinator shall submit to the ISO, for each hour of each Trading Day, a Day-Ahead Schedule that includes at least ninety-five percent (95%) of that Scheduling Coordinator's forecast Demand for each hour, for each UDC Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC Service Areas.

2.2.7.2.1.2 To the extent that a Scheduling Coordinator submits a Day-Ahead Schedule that reflects less than one hundred percent (100%) of its entire forecast Demand for the peak hour of that Trading Day in each applicable UDC Service Area, as set forth in Section 2.2.7.2.1.1, that Scheduling Coordinator must submit, along with its Day-Ahead Schedule, a list of the resources that the Scheduling Coordinator plans to rely upon during that Trading Day to meet its forecast peak Demand requirement.

* * *

2.2.12.3 Demand Information.

2.2.12.3.1 Daily Information. By ~~6:00~~10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

2.2.12.3.2 Preliminary Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than seven (7) days after the end of each week, which shall end at Sunday HE 24, data for the previous week (Monday through Sunday), in electronic format, comparing, for each hour of that week: (1) the Scheduling Coordinator's total Day-Ahead scheduled Demand by UDC Service Area, as submitted pursuant to Section 2.2.7.2, (2) the Scheduling Coordinator's total Day-Ahead Demand Forecast by UDC Service Area, as submitted pursuant to Section 2.2.12.3.1, and (3) an estimate of the Scheduling Coordinator's actual Demand by UDC Service Area.

2.2.12.3.3 Final Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than 60 days after the date for the submission of preliminary weekly data pursuant to Section 2.2.12.3.2, updated data in the exact same format as required in Section 2.2.12.3.2, reflecting the Scheduling Coordinator's total actual Demand by UDC Service Area for the applicable period.

* * *

2.2.18 Compliance with Scheduling and Data Provision Requirements. Pursuant to its obligation to notify FERC of any potential violations of Section 7 of the ISO's Enforcement Protocol, the ISO will routinely report any underscheduling behavior that it observes to FERC, for investigation as a potential violation of Section 7 of the Enforcement Protocol and/or FERC's Market Behavior Rule 2.

* * *

20.3.2 Confidential Information

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator;~~.~~

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Section 2.2.12.3.

Certificate of Service

I hereby certify that I have this day served a copy of this document on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Service Agreements under the CAISO Tariff.

Dated this 22nd day of September, 2005 at Folsom in the State of California.

Anthony J. Ivancovich

Anthony J. Ivancovich
(916) 608-7021