CALIFORNIA ISO

California Independent
System Operator

Appendix A

Appendix to the Approval on MRTU Issues Resolution for November 2005 Tariff Filing Memo dated October 12, 2005

Summary of CAISO Proposals to Resolve Policy Issues Discussed in the 2005 Stakeholder Process

Market Redesign Technology Upgrade Project (MRTU)

Summary of CAISO Proposals to Resolve MRTU Policy Issues Discussed in the 2005 Stakeholder Process

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California ISO

Market Redesign and Technology Upgrade (MRTU)

Summary of CAISO Proposals to Resolve Policy Issues Discussed in the 2005 Stakeholder Process

1. Introduction

When the MRTU market redesign effort began in 2002, the CAISO identified several critical objectives that were needed to improve reliability and address fundamental flaws in California's current electricity markets. These related to the flawed congestion management design and the collapse of the California Power Exchange. The primary objectives of MRTU are to: (1) perform effective congestion management in the CAISO forward markets (day-ahead and hour-ahead) by enforcing all transmission constraints so as to establish feasible forward schedules; (2) create a day-ahead energy market; (3) automate real-time dispatch so as to balance the system and manage congestion in an optimal manner with minimal need for manual intervention; and (4) ensure consistency across market time frames (day-ahead through real-time) in the allocation of transmission resources to grid users and in the pricing of transmission service and energy. Collectively these objectives comprise the over-arching goal of aligning the scheduling and operating incentives inherent in market prices with the requirements of reliable system operation, which has been the focus of the MRTU effort.

This document provides a summary of the CAISO's proposals on a set of MRTU policy issues that require resolution in order to enable the CAISO to file it's MRTU Tariff. The issues were discussed in the stakeholder process conducted by the CAISO from March through October of 2005. The proposals are based upon a series of FERC orders on MRTU issued from October 28, 2003 to September 19, 2005, which provided conceptual approval of the major design elements that comprise Release 1 of MRTU, scheduled to commence operation in February of 2007. The proposals contained in this document provide the additional details needed to complete the Release 1 market design and prepare the complete MRTU tariff language.

These proposals were developed by CAISO staff in dialogue with stakeholders, and were publicly presented for discussion at a series of stakeholder meetings held on August 16-18, August 30–September 1, and October 5-6, as well as a joint public meeting of the Market Surveillance Committee and the CAISO Board of Governors on September 22. On October 19, 2005 the CAISO Board will be asked to approve the proposals contained in this document, and based on the Board's decision these proposals will then be finalized in the MRTU tariff. The full MRTU tariff will be brought to the Board for approval on October 31, 2005.

Although the CAISO considers the proposals in this document to capture the final MRTU design to be implemented in Release 1, there are some other activities in progress at this time whose outcomes can affect the resolutions proposed here and could therefore require the CAISO to make adjustments to the Release 1 design. These other activities are: (1) the CPUC proceeding on Resource Adequacy, which has not yet issued a final decision; (2) a FERC inquiry on demand response in which the CAISO and the stakeholders participated, and on which FERC is expected to issue an order on MRTU-related matters including aspects of price aggregation for internal load; and (3) final review by the CAISO's software vendors of the detailed specifications for implementing these proposals. Should any of these activities require adjustments to the Release 1 MRTU design the CAISO will discuss the issues with stakeholders.

These CAISO proposals were developed in consideration of the comments submitted by stakeholders, and with the recognition that the stakeholder community does not unanimously support some elements. For some issues the alternatives considered would have impacts on reliability or market efficiency, and the CAISO had to weight these factors heavily in reaching its proposed solutions. In other cases the alternatives were mainly matters of equity among the stakeholders, and in these cases the CAISO attempted to propose a fair and reasonable balance among the various interests. The CAISO believes, overall, that the proposals presented here strike the best balance between the various concerns expressed by stakeholders, subject to the need to ensure that the comprehensive MRTU design is internally consistent from a whole system perspective, can be implemented in February 2007, and achieves the objectives of the CAISO's market redesign effort as stated above.

The CAISO's final recommendations on these issues are organized into four categories:

A. Resource Adequacy – MRTU Integration Issues
B. Transmission Rights Issues
C. Market Power Mitigation Issues
D. Spot Market Issues.

It is important to recognize that this document is not intended to be a comprehensive overview of the entire MRTU market design, but rather a limited summary of a subset of MRTU issues as described above. As a result there are certain groups of topics not discussed in this paper. First, the conceptual design elements submitted to FERC on May 13, 2005 are not discussed here. FERC ruled on these issues and granted conceptual approval of the CAISO's proposed direction in its July 1 order.

Second, this write-up does not address a number of issues and design modifications that have been identified or are under consideration for inclusion in MRTU Release 2. It also does not include details of certain Release 1 items that will be addressed after the MRTU tariff is filed in November 2005. The CAISO has determined that the additional details of these Release 1 items do not need to be included in the MRTU Tariff, but can instead be contained in Business Practice Manuals that will be written during 2006. The CAISO anticipates that efforts on the entire list of topics will begin early in 2006. At present the CAISO understands the following issues to be in this category:

1. CAISO backstop local area reliability procurement (Release 1)
2. Details of definition of EZ Gen Trading Hubs (Release 1)
3. Methodology for determining Day Ahead RUC procurement target (Release 1)
4. Methodology for post-DA release of RA-MOO resources (Release 1)
5. Details of Merchant Transmission CRR allocation (Release 1)
6. Modifications to structure of Day Ahead market passes (Release 2)
   - Use of bid-in demand rather than load forecast in Pre-IFM passes
   - Unrestricting the pool of resources in IFM pass
   - Eliminating use of extreme DEC bids on Pass 1 schedule
7. Ramping limits for Real Time pricing with Constrained Output Generation (Release 2)
8. Virtual or Convergence Bidding (Release 2)
9. Simultaneous RUC and IFM (Release 2)
10. Participating Load demand response in Day Ahead market (Release 2)
11. CEC proposal on rebate of loss over-collection for renewable resources (Release 2)

12. Scarcity pricing (Release 2)
13. Consideration of a full Hour Ahead Settlement Market (Release 2)
14. Dynamic pivotal supplier test for market power mitigation (Release 2)
15. Multi-settlement market for Ancillary Services (Release 2)
16. Consideration of import energy in RUC (Release 2)
17. Multi-day unit commitment in the IFM (Release 2).

2. Resource Adequacy – MRTU Integration Issues

2.1 Resource Adequacy based Must Offer Obligation

The Resource Adequacy-based Must Offer Obligation MOO (RA-MOO) will be specified in the CAISO tariff with the expectation that the CPUC will require that it will be incorporated by reference into bilateral RA contracts between LSEs and suppliers. This approach will ensure that:

- All RA capacity will be subject to a standard set of RA-MOO provisions that are consistent with the design of the CAISO markets and meet the CAISO's operational needs;
- These obligations on RA capacity will be explicitly addressed and compensated through the commercial terms of the bilateral RA agreement between the LSE and the supplier; and
- The costs to CPUC-jurisdictional LSEs of procuring RA capacity subject to the RA-MOO provisions can be addressed through appropriate CPUC cost-recovery mechanisms.

The purpose of this section is to specify a set of reasonable and efficient RA-MOO provisions with sufficient clarity that LSEs and suppliers can enter into agreements that are appropriately priced for the necessary services. CAISO believes that such RA-MOO provisions must specify rules and procedures whereby the supply capacity procured by LSEs is obligated to participate in the CAISO's spot market processes, including the Day Ahead Integrated Forward Market, the Residual Unit Commitment, the Hour Ahead Scheduling Process, and the Real Time Market. Although the CPUC's final order on RA has not yet been released, these RA-MOO rules and procedures are based on the CAISO's requirements for meeting system demand throughout each operating day and maintaining grid reliability in each local area of the grid. The CAISO is therefore actively engaged in the CPUC proceedings to see that the forthcoming CPUC order adopts the RA-MOO as proposed by the CAISO.

The CAISO proposes that the RA-MOO will include the following features:

1. The Day-Ahead MOO applies to all RA resources and all hours, with provisions for use-limited resources and, if deemed necessary, resources with other identified physical or legitimate limitations;
2. RA resources physically capable of operating must self-schedule or submit bids into the CAISO's Day-Ahead Market unless forced out;
3. Any inter-temporal constraints associated with RA bids submitted into the CAISO's market (such as minimum run time) must not be more restrictive than pre-specified physical or legitimate limitations;
4. RA resources that submit bids in DA (rather than self-scheduling 100 percent of their capacity) will be optimally scheduled in the CAISO's Day-Ahead IFM for Energy or Ancillary Services ("A/S");

5. RA capacity not scheduled[1] for Energy or A/S in the IFM market-clearing process will be considered in the ISO's proposed RUC process with a RUC availability bid equal to $0/MW;
6. RA capacity selected in RUC is not eligible to receive an availability payment from the CAISO (since its fixed costs will be covered under its resource adequacy contract);
7. Long-start units (start-up + minimum run time = 5 hours or greater) not scheduled in the Day-Ahead IFM or committed in RUC will not be obligated under the MOO to be on-line and available the next day;
8. Short-start units (start-up + minimum run time < 5 hours) must self-schedule or offer into the ISO's proposed combined Hour Ahead Scheduling Process (HASP) and Real Time Market for each hour of the operating day, even if not scheduled in Day-Ahead unless released from this obligation by the CAISO after the DA processes.

The specific obligations of the different resource types are the subject of this paper and more fully defined below. These resource types are:

- Short Start (SS) Resources
- Long Start Resources
- Partial RA Resources
- Partially Dispatched RA Resources
- Imports
- Use Limited Resources
- Exports.

2.1.1 Short Start Resources

The CAISO has needs for capacity after the DA IFM/RUC have completed due to forced outages or actual loads higher than the day-ahead load forecast. While the magnitude of this need for additional capacity on a system-wide basis may only be a few thousand megawatts, it is not known in advance where the need will occur. Transmission limitations require that adequate additional capacity throughout the system be available to address these contingencies and assure reliability. Therefore, the CAISO is advocating that RA-MOO for short start resources should not expire after the Day-Ahead market. RA resources with the physical capability to respond to a CAISO dispatch instruction should have the obligation to be available into Real-Time. The necessary compensation for meeting the offer obligation into Real Time would be established between LSEs and suppliers through their negotiation of bilateral RA based contracts.

In white-papers provided by the CAISO earlier this spring, the CAISO had proposed a definition of short start resources as those resources with cold start times plus minimum run times of less than 5 hours. In recent stakeholder meetings, the CAISO had been discussing a definition where short start resources are those resources with the ability to perform a cold start in less than 2 hours.[2] The notion being that RA resources with start-up times greater than 2 hours but which have not been committed in the DA would no longer have a RA-based offer obligation. The CAISO has further considered this definition in conjunction with the MRTU software design

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1 A "scheduled" resource is based upon the final schedules coming out of the Day-Ahead process.

2 There are approximately 100 units for a total of 7,000 MWs that meet this criterion. In addition, hydro resources include an additional 139 units with a total capacity of 10,000 MWs; yet, these are also use-limited resources and may not be available for most conditions. Furthermore, the CPUC is expected to establish a monthly obligation; therefore, much of this capacity may not be RA resources that are subject to a RA-MOO in any given month.

and CAISO operational practices and believes an appropriate criteria is to define SS units as originally proposed: Any resource that can perform a cold start in combination with a minimum run time that is less than 5 hours.

The CAISO intends to utilize this definition because the MRTU software has been designed with a 5-hour look ahead[3] for real-time dispatch purposes and this longer time horizon offers economic and operational benefits. These are derived primarily from the CAISO making efficient decisions regarding starting up of resources that require start-up time plus minimum run-time of less than 5 hours.[4] By applying this approach, the CAISO will be providing increased dispatch efficiency by allowing some resources that otherwise would have shut down prior to the end of the first hour(s) to stay committed if determined to be necessary in the next hour(s).

The CAISO has consistently conveyed that it cannot know in advance which resources will be needed where on the system in real-time (due to Forced Outages and other contingencies). Thus, the practical solution now is for the establishment of a clear RA-MOO that defines the resource obligations to be available to the CAISO in Real-Time where the total of start-up and minimum runtime is less than 5 hours unless the CAISO determines that it does not need the resource to meet its operating requirements.

Some stakeholders have strongly urged that the RA-MOO should modify the current approach by ending the offer obligation after the DA process has completed. They argue that the CAISO should pay for the post DA service if the CAISO requires additional uncommitted capacity beyond that procured in the DA markets. In addition, stakeholders have voiced their concern about the quantity of short-start resources that may need to be available in real-time. In defining this short-start obligation the CAISO is explicitly assuming that the CPUC will adopt the CAISO's proposed Locational Capacity Requirements and that all locational capacity is obligated to make itself available for all hours of everyday, i.e. 24x7. Of the 4,900 MWs thermal resources that meet the short-start criteria, approximately 4,200 MWs are located within the load pockets. Ultimately, the load pocket resources as well as hydro, imports, and partially dispatched units may be mostly committed during peak load months and many of these resources may not be subject to an RA-MOO in off-peak months because the CPUC is expected to establish a monthly obligation that reduces the amount of RA resources compared to a peak month.

The CAISO believes it can accommodate the stakeholder concerns about the quantity of resources required to be available into real-time. The CAISO proposes to design a post DA mechanism that would potentially release a portion of short-start resources not committed in the DA processes that are not anticipated to be needed in real-time, e.g. recovery of operating reserves after a contingency. The CAISO anticipates that a manual mechanism can be developed and made available for Release 1 of the MRTU project. The CAISO will work with stakeholders to design the process and parameters that would entail an effective release mechanism that would be in effect during Release 1. CAISO does not anticipate that it will have had sufficient opportunity to fully develop the details of the release mechanism when it files the MRTU tariff as expected on November 30. The CAISO intends, however, to include in its November 30 filing tariff language that will enable it to adopt such programs and will in the

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3 This look ahead is currently considering the forward period of 255 minutes. Thus, any resource whose total start-up and minimum runtime is greater than 255 minutes will not be considered for commitment because the application cannot evaluate the total cost of the decision.

4 The total population of resources that meet this new criteria is actually less than that under a simple two hour start-up. There are approximately 93 units for a total of 4,900 MWs of thermal assets that meet this criterion. In addition, hydro resources include an additional 130 units with a total capacity of 9,200 MWs. As noted above, the hydro resources are also use-limited resources and may not be available for most conditions. Furthermore, the CPUC is expected to establish a monthly obligation; therefore, much of this capacity may not be RA resources that are subject to a RA-MOO in any given month.

meantime and subsequent to that filing continue to further develop the details of the programs with its stakeholders. Ideally, this effort can be completed in the early months of 2006, thus allowing for LSEs and resource owners to incorporate the revised obligations in their RA contract negotiations.

Conversely, the CAISO does not believe it can address the stakeholder concern to end the RA-MOO in the DA timeframe and have the CAISO pay for post DA service through its markets in Release 1 of MRTU. For example, some stakeholders have suggested that the CAISO increase its procurement of the spin/non-spin product under the MRTU design. The CAISO does not believe this to be an appropriate solution because the spin/non-spin requirements are significantly more stringent than the operating reserve replacement that that needs to be available in 60 minutes. Thus, increasing the spin/non-spin requirements may lead to excessive prices and/or inadequate supply. The CAISO is open to considering market design solutions versus this RA-MOO to address these operational reliability requirements post Release 1.

In summary, the CAISO continues to believe the short-start resources meeting an RA based must offer obligation must be available until real-time unless released earlier by the CAISO. The CAISO would notify this subset of the RA short-start resources that they have been released from the RA-MOO after the DA process has been completed. This definition of the RA-MOO is the best feasible option (one rule for all market participants, and it does not require complex software to implement), it is equitable in that it treats all resources with comparable properties the same, and it is known in advance of the RA bilateral negotiations and thus can be factored into the price.

2.1.2 Long Start Resources

The original MRTU design contemplated a multi-day unit commitment process. However, complexities in the software have eliminated this functionality in the currently proposed IFM and developed software applications. Thus, the DA/RUC unit commitment will be completed at approximately 13:00 hrs in the DA for the following day. Clearly, not all resources must be operating during the first hour of the operating day. However, they must be capable of providing service as the system is beginning to build towards the expected day's peak. Yet, there are a number of resources whose cold start time can range from 12 to 24 hours or more.[5] Thus, it is necessary to have an appropriate functionality for committing long start resources.

The IFM software specification requires IFM to meet performance requirements while simultaneously optimizing over 24 hours. Currently there is no performance requirement for the IFM software to simultaneously optimize more than 24 hours at a time. However, the RUC software is presently designed to support up to 7-day unit commitment where each day's unit commitment is optimized one day at a time. This RUC approach will allow the CAISO to make efficient decisions regarding starting up resources that require start-up time notification greater then 18 hours (long-start resources). Yet, RUC is also able to support up to a 48-hour simultaneous optimization. Therefore, CAISO will initially use the 48-hour simultaneous approach to provide some increased efficiency by allowing some resources that otherwise would have shut down prior to the end of the first day to stay committed if determined to be necessary the next day via the RUC process.

Looking towards the long-term solution, the CAISO proposes to pursue a multi-day unit commitment IFM and/or longer than 2-day simulation RUC commitment after the initial MRTU release. This approach will allow for a coordinated evaluation of the software systems prior to implementing a multi-day IFM unit commitment.

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5 Long-start units (start-up + minimum run time = 5 hours or greater) not scheduled in the Day-Ahead IFM or RUC will not be obligated under the MOO to be on-line and available the next day.

2.1.3 Partial RA Units

A partial unit is a physical resource that has a qualifying RA capacity capability that is not fully committed to meet an RA obligation in the CAISO control area. Thus, a portion is obligated under a RA-MOO but the remainder is not required to make itself available for ISO commitment or dispatch.6 CAISO believes it can accommodate the notion of RA resources having an obligation to offer only portions of their capacity subject to the constraint that a resource be represented (scheduled) by a single Scheduling Coordinator (SC). The MRTU design is premised on the single SC assumption and the CAISO believes this market rule should continue under MRTU because it allows SCs to enter into multi-party arrangements but simplifies the CAISO operation/administration by establishing a single interface party for each resource.

CAISO believes an accommodation for partial units is fairly straightforward to achieve. The following changes will allow for a resource to be split between a portion that is RA and a portion that is Non-RA. First, MRTU will need the ability for RUC bids to contain multiple segments, e.g. (zero price RA portion, non-zero availability bid for non-RA portion) Second, the MRTU applications must perform a calculation to subtract the schedules coming from the Integrated Forward Market from a partial unit resource to determine the portions of capacity that come from RA and Non-RA for settlement purposes.

For example: The Non-RA portion does not have any RA-MOO obligations but may submit bids with a non-zero availability price. Thus, an SC can bid a 400MW resource split between 200MW as RA and 200MW as Non-RA. In the DA, the IFM may schedule 300MW and the remaining 100MW is committed in RUC. Under these conditions, the resource owner will be paid an availability payment for the 100MW of RUC capacity because it is assumed the RA portion and 100MW of Non-RA was already committed in the IFM.

Ultimately, the CAISO has determined that its support of partial units is not a difficult implementation but would require software changes. Therefore, a change order is required to fully determine the effects on the MRTU project completion. The CAISO is currently working with its MRTU software vendor to determine the impact to the project implementation schedule.

2.1.4 Partially Dispatched RA Resources

An effective RA-MOO applies to all RA resources for all hours, with provisions for use-limited resources, legitimate physical limitations, etc. This is accomplished by establishing the clear obligation that RA resources must self-schedule or submit bids into the CAISO's Day-Ahead Market unless forced out or further subject to additional offer obligations for short-start resources. The CAISO expects that the Day-Ahead IFM/RUC commitment of a resource will result in either a full energy schedule or a schedule that results in the commitment (start-up) of the unit, but only a partial dispatch of the energy. For the RA resources that are committed, but only partially dispatched, the RA-MOO will extend into real time. The remaining capacity, that is uncommitted, must continue to be offered into the real-time but may revise its Day-Ahead energy bids for that portion of the capacity that was unscheduled in the Day-Ahead process.

Stakeholders have voiced their concern that they can't sell their output into other markets after the Day-Ahead process. In fact, resources are not precluded from selling exports during or after the Day-Ahead process. The sales are made from the CAISO market rather than being linked to a specific internal resource. The CAISO believes this approach to the remaining portion of a partially dispatched RA resource is comparable to a short-start unit and thus should receive comparable treatment. Therefore, the CAISO will advocate before the CPUC that specific requirements must be established in the bi-lateral RA contracts that are consistent with these

[6] The CAISO is able to accommodate the split of the resource capacity. However, this design does not accommodate the notion that allows a resource to be RA for some hours and not for others.

CAISO tariff provisions. Similar to SS resources, the remaining uncommitted portion of the partially dispatched RA resources will be eligible for release from their RA-MOO after the DA processes.

2.1.5 Imports

The imports satisfying RA obligation have "must offer obligations" consistent with the minimum duration of such a resource as it is reflected in the RA compliance report by the relevant LSE demonstrating compliance with its RA obligations. Ideally, imports would reflect characteristics similar to internal resources, e.g. one-hour start-up time and one-hour minimum up time. In practice the CAISO understands that imports fall into two broad categories, single hour and multi-hour blocks.

Any inter-temporal constraints (such as multi-hour blocks) if mutually agreed upon by the seller and the LSE, must be explicitly specified in the RA report. This will ensure that import providers are not able to submit bids that have sufficient characteristics to effectively withhold the RA capacity.7 Therefore, the CAISO must be allowed to scrutinize and determine whether such constraints can be accommodated without unduly undermining the reliability value of the import in meeting CAISO's resource requirements.

No constraints may be imposed beyond those explicitly stated in the RA report when the import is satisfying the RA obligation to schedule or bid into the ISO markets. The RA-MOO obligation for import RA in the day-ahead and real-time markets depends on the temporal constraints associated with the import. Where the import can be dispatched in hourly increments, the import is treated like a short start unit and has RA-MOO both on the day-ahead and in HASP/RT. When the import is a multi-hour block, the import will have no further obligation if it is not cleared in the Integrated Forward Market (IFM) and not designated as RUC capacity.

The CAISO expects that in some instances suppliers will fulfill their RA contracts by offering multi-hour energy blocks into the IFM with economic bids. The current IFM design will observe multi-hour block constraints on import supply bids when it clears the energy market. However, any multi-hour block constraints associated with import supplies will be recognized in the IFM only and not in the subsequent processes. The RUC will view such supplies as available for designation as RUC capacity as needed in each hour of the subsequent day for which they were bid into the IFM, without any requirement in the RUC optimization to recognize a multi-hour block constraint or any other inter-hour constraints. Thus, any RA import supplies designated as RUC capacity will then be required to be self-scheduled or offered with economic bids into the HASP for each applicable hour. RA supply from multi-hour block energy imports that is not cleared in the IFM and is also not designated as RUC capacity will have no further obligation to be available to the CAISO on the next operating day.

The CAISO believes, as noted above, that any multi-hour block imports that are expected to qualify as an RA resource, must be capable of hourly selection if not fully committed in the IFM process. Further, if the block resource is selected in RUC, the resource must be dispatchable in those hours in the HASP and real-time market. The CAISO will advocate at the CPUC that these specific requirements must be established in the bi-lateral RA contracts between LSEs and suppliers.

2.1.6 Use-Limited Resources

Use-limited resources ("ULR") are valuable resources in power system operations, and therefore should count toward meeting a RA obligation. Therefore, under an effective RA

[7] For example: An importer creates a block bid that establishes a high minimum energy level and a very long minimum duration to avoid being selected by the CAISO but still meeting RA qualifying criteria.

program, a LSE will be able to “count” ULRs to fulfill its RA obligations. However, by definition, these types of resources are not capable of running for all hours of a given operating day.

The CAISO proposes to manage ULRs as follows:

- A ULR must be able to operate for a certain number of consecutive hours each day to count for RA purposes.
- A ULR must “offer” (i.e., schedule or bid) to the CAISO for the amount of MWhs that the ULR is counted towards meeting a RA requirement[8].
- A resource must initially register with the CAISO as a ULR. The resource must further submit a CPUC or local regulatory designation as a ULR. Otherwise, it must submit certain historical operating data, which will be evaluated by the CAISO.
- Using the MRTU software, the CAISO will “optimize” the use of the ULR in the Day Ahead market while recognizing the constraints of the calendar year Use Plan.
- The CAISO and LSE will cooperatively develop an annual Use Plan, which is intended to communicate how an LSE is intending to utilize its limited resource. This is turn will give the CAISO an opportunity to engage in a forward dialog that may contemplate shifting the use of the ULR due to foreseen extraordinary conditions.
- As a result of the actual usage of an ULR, it may be appropriate for the LSE to update the Use Plan on a monthly basis.
- The CAISO will review ULR use at end of each month to determine how actual use has tracked relative to the Use Plan. This review will be based on schedules and bids submitted to the CAISO during the preceding month.
- The CAISO is not proposing financial penalties for variations in actual use from the Use Plan. The CAISO will monitor to see how closely actual use tracks what the LSE usage plan to inform the CAISO on the future availability of ULRs.

The RA-MOO for a ULR will be implemented like any other RA resource. To the extent the ULR’s daily capacity has been bid or self-scheduled in the Day Ahead market, no further action is necessary, unless it is subject to additional offer obligations for short-start resources or rescheduling of the energy by the CAISO in real-time is necessary for system reliability.

If requested by the CAISO, the ULR will attempt to reschedule the energy in recognition of the system reliability concern, but only to the extent that the change is possible without violating its daily energy limit. In the case of an emergency, in real-time the CAISO may request further assistance from the ULR, recognizing that the ULR may not be capable of responding due to the resource's operating criteria.

2.1.7 Exports

One of the underlying issues that affect the position of stakeholders on the RA-MOO is MRTU’s treatment of exports. The CAISO believes MRTU affords market participants significant flexibility to take advantage of other opportunities to sell their output in markets after the CAISO Day-Ahead commitment process.

The design of the Day-Ahead IFM does not differentiate exports supported by RA and non-RA resources. Thus, any load bid into the market will be competing for available supply based on the load bids. As a result it is possible that RA resources may be committed and awarded to provide export energy while a Day-Ahead bid for internal load has not been satisfied. In sum, all price-taker load and exports not associated with ETC or TORs have the same priority and RA

[8] An RA resource may not meet the RA-MOO obligation by submitting bids that restrict the CAISO use during peak operating conditions.

resources are free to serve export load as long as the export is not explicitly linked to the RA resource.

When running Day-Ahead RUC, capacity will be committed to meet the difference between CAISO load forecast and load that cleared in the Day-Ahead IFM. Exports that clear the Day-Ahead-IFM will be considered as a self-schedule in RUC. There is no mechanism for the Day-Ahead RUC to identify those exports sourced from RA resources from those exports being sourced from non-RA resources. As a result, RUC will, only to the extent possible, attempt to meet the CAISO load forecast from all remaining uncommitted bid in RA and non-RA capacity. If insufficient capacity is available, Day-Ahead-RUC may not be able to meet the CAISO load forecast. In such cases, there is no mechanism designed to curtail or recall exports in the DA.

Further, HASP has no mechanism to differentiate between exports sourced from RA resources from those exports sourced from non-RA resources. Therefore, RA resource owners who have not been committed in the DA IFM/RUC process are free to look for opportunities to sell their capacity to markets outside the CAISO control area. Any such transactions can be accommodated in the HASP by the appropriate bid behavior so long as the CAISO load forecast can be satisfied, e.g. high export load bid and low generator bid.[9] Exports associated with ETC, TOR will have a scheduling priority.

Discussion of Stakeholder Comments

The CAISO has received many comments from stakeholders related these topics and has endeavored to balance the varied perspectives. This document is intended to provide the summary of those discussions and finalize the requirements for the Resource Adequacy-based Must Offer Obligations that RA resources are required to meet.

During the August 30, 2005 stakeholder meeting, stakeholders raised several concerns. The CAISO has attempted to directly address many of those above. Here the CAISO responds to three additional issues:

Issue 1: For RA resources/capacity that is not committed but is obligated to offer into real-time, should the capacity receive an additional payment?

Suppliers strongly insist that resources such as short-start resources have a value for being flexible enough to offer into the HASP/ Real-Time market and if the CAISO does not intend to compensate such resources for the added flexibility for remaining available, it is unreasonable to expect such a resource to be obligated to make its uncommitted RUC capacity available to the CAISO. Furthermore, they argue that unless the CPUC explicitly extends the obligation of RA resources beyond the Day-Ahead market and requires LSE to procure a certain amount of short-start capacity, it is inappropriate for the CAISO to unilaterally extend the obligation without some form of additional compensation. Without such a requirement set by the CPUC, suppliers are concerned that there will be no premium delivered from negotiations with LSEs for the more flexible RA capacity.

While the CAISO agrees that ultimately it is appropriate for the CPUC to clarify the obligation of short-start RA resources, the CAISO believes it is appropriate to expect RA capacity that is still physically available to make such capacity available to the CAISO even if it has not been committed in the DA processes. In setting such a requirement, the CAISO is not limiting the resource's opportunity to engage in bi-lateral arrangement with internal or external demand so long as CAISO is able to meet its forecasted load. The CAISO further understands that there may be additional costs for maintaining this availability and for having the flexible capacity value

[9] While the Day-Ahead IFM rules allow an export load to be self-scheduled, current HASP rules do not allow self-schedule export in excess of Day-Ahead export levels, unless the export is associated with an ETC, TOR or wheel through; therefore, an export must submit a bid to be considered.

offered to the HASP/Real-Time market. To that point there are already several ways for short-start RA resource to extract the additional value for the added flexibility a short-start RA resource provides:

1) Owners may participate in the ISO A/S markets

2) Owners may negotiate a premium in their RA contracts

3) Owners may revise their energy bids after the DA process

4) Owners may engage in export transactions and schedule appropriately

5) Owners may already be obligated by the Locational Capacity requirements and receive compensation.

Because of these opportunities to receive post DA value for the short-start capacity, the CAISO believes there is already sufficient means for owners of short-start resources to value and be compensated for their short-start capabilities. The remaining risk that results is primarily derived from two cases associated with export transactions; 1) CAISO declares a system emergency and is required to cut export schedules, 2) CAISO has a resource shortage after the DA process and one or both of the source and load sides of the export transaction are not served by the CAISO. It should be noted that this same set of risks exist in the eastern ISO markets and the CAISO understands that those markets have not been required to invoke their export curtailment authority. Finally, the CAISO has indicated earlier in this whitepaper its willingness to further consider market-based approaches that appropriately address this issue subsequent to Release 1 of MRTU.

Issue 2: Should RA SS resources committed in RUC receive an advisory notification?

Ideally, the CAISO should communicate the RUC capacity commitment obligation for all capacity that RUC relied upon. While RUC may be relying upon the short-start resource availability, this does not imply that the resource will have to actually be started.[10] The current software design cannot provide an “advisory only” commitment. The CAISO understands that what is actually needed is a RUC advisory commitment decision that is separate from the actual start-up decision that occurs in HASP/RT. In this way, a short-start resource would know if its availability was necessary to meet the CAISO forecast load in RUC but it would wait for an actual start-up instruction to start. Furthermore, the ability to identify the need for a non-RA short-start resource in RUC is necessary to: 1) ensure such a non-RA short-start resource is notified to be available for start-up and dispatch in HASP/RT and 2) compensate the non-RA short-start resource with a RUC availability payment. The CAISO is exploring the feasibility to include this functionality in Release 1 software.

Issue 3: What is the RA-MOO for RA resources that are effectively not dispatchable because the resource output is accepted as it is delivered?

The CAISO expects that certain resources generally referred to as must-take resources (such as run of river hydro and QFs) will be allowed to count for towards a LSEs RA obligation. Yet, on any given day the energy scheduled from this type of resource will likely vary from the amount of capacity used to establish the qualifying capacity for the RA demonstration. Therefore, the CAISO believes the RA-MOO for such resources will consist of the obligation to submit schedules and bids consistent with the must-take obligation. In cases where the resource is unable to achieve its qualifying RA capacity, the SC representing the resource must submit to the CAISO the appropriate derates to indicate its inability to provide its full RA obligation.

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[10] Variations in the real-time system conditions compared to those assumed in the DA processes may result in a resource not actually being started, e.g. a lower actual load than that used in the DA.

2.2 Resource Adequacy Requirements for Non-CPUC Jurisdictional LSEs

The CAISO reiterates its preference for the development and application of uniform RA requirements among all LSEs within the CAISO control area. Uniform standards lessen the likelihood that one LSE can lean on the reserves of another LSE and generally enhance the efficiency and effectiveness of administration. The CAISO notes, however, that notwithstanding its preference for consistent RA requirements, and its ability to condition the use of the CAISO controlled grid on compliance with such RA requirements, it desires to work cooperatively with non-CPUC jurisdictional entities and their Local Regulatory Authorities ("LRAs") to ensure reliable grid operation, equitably allocate RA responsibilities, and acknowledges any characteristics particular to the public LSE community.

During the recent weeks, the CAISO has been discussing alternative RA proposals with various non-CPUC jurisdictional entities. These discussions are still ongoing and no firm commitments have been adopted. However, the CAISO is confident that the parties are working towards similar goals for an effective and comparable set of RA obligations. The CAISO anticipates it will be able to develop the appropriate tariff provisions and share with stakeholders as the MRTU tariff-drafting project continues.

2.3 Resource Adequacy Compliance and Enforcement

Over the recent months, most efforts have been focused on the specific provisions of the RA policy. As a result, the details of the RA reporting and compliance program have had limited progress. The CAISO continues to believe that the RA program will require a forward reporting obligation; i.e. CPUC will require "year-ahead" and "month-ahead" showings of compliance with RAR. In addition the RA program will require resources to be made available to CAISO for DA and RT markets through schedules and bids. Therefore, the CAISO will monitor schedules and bids and assess whether the RA resources were made available to CAISO consistent with the established obligations. In the coming weeks, the CAISO anticipates it will be able to develop the appropriate tariff provisions and share with stakeholders as the MRTU tariff-drafting project continues.

2.4 CAISO Local Reliability Backstop Procurement

Previously the CAISO had proposed to create a new contract that would provide for backstop procurement by the CAISO of resources needed for local reliability should the LSE RA procurement prove to be insufficient to support reliable system operations. The CAISO has indicated that any mechanism it adopts will be designed for short-term procurement (e.g., on the order of one month) to ensure that CAISO procurement does not provide an attractive alternative to bilateral contracting for either buyers or suppliers. At this time the CAISO believes a tariff based rate approach appears to be a feasible mechanism for this purpose. The CAISO will proceed to define a backstop mechanism which will be guided by the following principles: (1) RA is an Load Serving Entity (LSE) based obligation to ensure the CAISO has sufficient capacity, (2) RA resources need to receive appropriate compensation, and (3) CAISO procurement has the potential to distort the incentives for bilateral contracting, and therefore it should only supplement and not supplant it.

The CAISO recognizes that the development of an appropriate backstop procurement mechanism is essential prior to the implementation of the CPUC RA program. Therefore, the CAISO remains committed to developing this solution with stakeholders over the coming months.

3. Transmission Rights Issues

3.1 CRR Allocation for Load Within the CAISO Control Area

The subject of Congestion Revenue Rights (CRRs) has been a matter of the greatest concern to stakeholders because CRRs are the primary means for users of the CAISO grid to hedge or protect themselves against the financial risks associated with variable hourly congestion charges under MRTU. From the CAISO perspective, the congestion charges that the CAISO collects in its energy markets are funds that must be returned to market participants through some transparent and equitable means, and the CRR is an instrument for affecting this return. The CRR allocation design concept, as filed with FERC in July 2003 and approved in October 2003, is intended to accomplish both the hedging and the congestion charge refund objectives for the customers located within the CAISO control area.

Although the present proposal has been under development through the stakeholder process over the past several months, recently some parties have argued that the CAISO should shift to a very different approach to the one described below. In response, the CAISE has twice over the past few weeks asked parties to submit written comments on alternative approaches that were suggested. First, in early September in response to stakeholder suggestions the CAISO asked parties to comment on whether they would prefer a full auction process for CRRs in which the auction revenues are used to reduce transmission access charges, instead of the proposal to allocate CRRs so as to provide each LSE an effective congestion hedge. Although not all parties responded to this inquiry, the dominant view among those who did respond was to stay the course and continue to develop the allocation proposal. In particular, the entities that favored staying the course were those who represent the vast majority of end-use load within the CAISO control area.

Second, in early October in response to concerns raised and ideas discussed at a September 22 joint meeting of the CAISO Board and the Market Surveillance Committee, the CAISO asked stakeholders to comment on whether they would prefer an alternative procedure for allocating CRRs to the one being developed through the stakeholder process. The idea of the alternative would be to simplify the process for both the CAISO and the LSEs eligible for CRR allocation by allocating CRRs in a pro rata fashion, which would give each LSE an appropriate share of the congestion revenues collected by the CAISO through the spot markets, but would not try to provide each LSE a congestion hedging set of CRRs that reflects each LSEs exposure to congestion charges. At the October 5 stakeholder meeting, members of the MSC described one possible way such an alternative procedure could be designed, but at the present time there is no well specified and stakeholder design for such an alternative. Stakeholder comments on this question are due on October 10, which will not be in time to include the results in the final version of this document for the package of Board documents for the October 19 meeting. The CAISO staff will provide a verbal summary of the received comments at the Board meeting.

Although the stakeholder comments on the new alternative cannot be reported in this document, the new alternative was discussed conceptually for several hours at the October 5 meeting, and as a result staff can identify some important criteria the Board should consider in deciding whether to approve the CRR allocation proposal that has been developed with stakeholders (Option A), or to direct CAISO management to pursue the new alternative (Option B).

First, the question at hand applies specifically to LSEs who serve load within the CAISO control area, and they will be the parties most affected by the choice of CRR allocation approaches. The CAISO's usual concerns about reliable operation and market efficiency are not major issues in the question of how to allocate CRRs. Although inefficient economic incentives could arise if allocation is not designed carefully, this concerns can be addressed effectively under either Option A or Option B. Therefore the approach taken by CAISO staff in this process has been to focus primarily on fairness as expressed by the affected parties, and to try to develop a proposal that balances these parties' concerns as equitably as possible.

Second, changing course and pursuing Option B at this time will most likely result in a delay, at the very least in the filing of the MRTU tariff language related to CRR allocation. In the most optimistic Option B scenario, CAISO staff and stakeholders would quickly settle on an Option B design within at most two weeks after a Board decision to pursue this option, and the design would be incorporated in tariff language for filing by November 30 without missing a beat. This scenario does not seem realistic, however. Discussion at the October 5 stakeholder meeting indicated that there are divergent views on how to design the alternative. Moreover, key CAISO staff will need to be diverted from other critical MRTU activities to work on the Option B design. Under a more realistic scenario, then, the development of the Option B design would carry over into early 2006 and the associated tariff language would be filed some time in the first quarter. At this time it is not possible to estimate the impact of such a scenario on the ultimate MRTU start-up date.

Third, the objective of simplifying the CRR allocation process may play out differently for the LSEs than for the CAISO. Although the Option B approach would probably enable the CAISO to operate with fewer full-time staff assigned to CRRs than under Option A, it may not be the same for the LSEs. The reason is rooted in the switch from allocating a congestion hedging set of CRRs under Option A, to allocating a simple pro rata share of congestion revenues under Option B. Many of the LSEs want to be allocated congestion hedging CRRs, not just shares of the congestion revenues, to hedge the congestion risks associated with existing long-term supply arrangements. If the CAISO adopts Option B, these LSEs will then have to invest time and effort in the CRR auction process to try to reshuffle their allocated CRRs with the other auction participants to obtain the CRRs they need for hedging. Thus the costs avoided by not doing Option A may be fully offset by the additional costs and risks associated with having to participate in the CRR auctions.

The rest of this section is devoted to a description of the CRR allocation proposal developed by CAISO staff in the context of the 2005 stakeholder process.

3.1.1 The Proposal Developed in the Stakeholder Process

The proposal contained in this document represents the CAISO's synthesis of several rounds of public discussion, written comments from stakeholders, examination of rules and procedures adopted by other ISOs, and assessment of the results of CRR Study 2, to craft a proposal that the CAISO believes strikes a reasonable, equitable and workable balance of the objectives of CRR allocation and the concerns expressed by stakeholders.

At the outset it must be noted that the matter of CRR allocation is predominantly a matter of equity more than a matter of grid reliability or market efficiency. There are some ways in which CRR allocation could create inefficient incentives, and the CAISO's proposal recognizes these and avoids them. But beyond these concerns, most of the divergence in views among the parties derives from different perspectives on how to define and achieve equity. The CAISO's proposal is designed, therefore, primarily with the objective of fairly and transparently balancing these equity concerns.

Several specific policy and design issues have been discussed in the last several rounds of meetings and comments, on which the present proposal lays out the CAISO positions. It is worth noting these at a high level before getting into the details of the proposal.

1. The question of allocation of CRRs versus full auction. In response to this question, which was posed by the CAISO in advance of stakeholders submitting their September 8 comments, a predominant – though not universal – preference was expressed for staying

with the allocation approach. As a result the CAISO remains committed to developing a workable and equitable allocation methodology that is supported by stakeholders.

2. A related matter of principle is whether CRR allocation should reflect parties' exposure to congestion costs, or should reflect their support for the embedded costs of the grid through payment of access charges. The latter approach would be simpler to implement, but the comments by the load-serving entities (LSEs) indicated a predominant preference for CRR allocation that reflects their exposure to congestion costs under LMP, and therefore the CAISO proposal takes this approach.
3. The question of CAISO verification of nominated CRR sources. The stakeholders differ on two approaches to the matter of CAISO verification of eligible sources for CRR nomination. (A) The CAISO proposal is to conduct verification of sources the first year only – for both the annual and the monthly processes. After the first year CAISO source verification would cease and instead the principle of "grandfathering" would apply. That is, LSEs would be able to request renewal of CRRs allocated to them in the prior period, and the CAISO would award these renewal requests with priority over requests for new CRRs. To be clear, the CAISO intends grandfathering to apply only to CRRs that were allocated to the LSE in the prior period; it would not apply to CRRs obtained through the auction or through secondary transfers from another LSE. There is substantial support among the stakeholders for this approach. (B) Several parties do not support grandfathering and want the CAISO to perform source verification on an indefinitely continuing basis.

   There is an important reason not to perform ongoing verification of the sources LSEs nominate for CRR allocation. The LECG consultants, who performed CRR Study 2, wrote the CRR Study 3 Report and assisted the CAISO in developing its CRR allocation proposal, as well as the CAISO's Market Surveillance Committee, have all raised strong concerns about forward-looking verification of CRR sources for allocation eligibility. Their concerns center around the distortion of incentives for both LSEs and suppliers that is created when contracting parties are aware that their contracts can be used to obtain free allocations of CRRs. Experience of other ISOs has shows that this concern is not just theoretical but has occurred in practice.
4. Grandfathering. Grandfathering is the means by which LSEs may request to renew a portion of their current holdings of allocated CRRs and have a high likelihood of receiving them for the next year. Thus grandfathering provides multi-year durability to CRRs, which is needed to support long-term contracting, and investment in new generation. As a secondary benefit, grandfathering eliminates the need for the CAISO to perform verification of nominated CRR sources after the first year, which simplifies the ongoing allocation process.

   Among the parties who oppose grandfathering there seem to be two main concerns. First, there is a concern that some LSEs will hold onto valuable CRRs even when they no longer serve load from those CRR sources, thereby limiting the ability of other LSEs to obtain a fair share of valuable CRRs through the allocation process. The second concern is that the key concept that makes grandfathering work under the CAISO's proposal is the fact that grandfathered CRRs are allocated first, before requests for new CRRs, and this could put LSEs gaining load at a disadvantage.

   The CAISO recognizes these concerns, but believes that the overall balance and equity of the proposal are better served by incorporating provisions to mitigate the concerns rather than by eliminating the grandfathering feature. In this regard the proposal limits the quantity of CRRs that can be grandfathered, and includes provisions to ensure that customers who exercise retail choice and change LSEs are not harmed with respect to CRR coverage compared to customers who do not change.

Based on a reading of the comments, another way to mitigate the concerns of the parties who oppose grandfathering will be to ensure that the first-year allocation in which sources are verified by CAISO is viewed by all parties as fair and consistent with their hedging needs. If all parties receive an equitable first-year allocation, they will all benefit from the assurance of year-to-year continuity made possible through the grandfathering feature.

5. Retail Access. There is also disagreement among parties regarding how CRR eligibility of LSEs should be affected when some load migrates under retail access (direct access). The main alternatives at issue are: (A) the LSE that loses load must have a reduction in the CRRs it can "grandfather" in subsequent periods; versus (B) the LSE that loses load does not have its grandfathering rights reduced as long as its total quantity is within its MW eligibility. The CAISO proposes to adopt option (A) and views it as a necessary feature for achieving the objective of enabling customers who change LSEs to maintain CRR coverage.
6. Iterations with participants in each allocation process. This CAISO proposal divides each allocation process into tiers (described below) where each tier has its own SFT, and participants receive the results of the latest tier prior to submitting their nominations for the next tier. This is an important feature for maximizing the release of CRRs (subject to simultaneous feasibility of course) and maintaining equity when it is necessary to prorate CRR awards, while maximizing participant choice.
7. Net revenues from marginal losses. On September 15 the CAISO issued a new proposal on how to credit net loss revenues back to demand. This new proposal keeps the net loss revenues separate from the CRR balancing account and credits the funds back to demand on a flat per-MWh hour basis on each settlement statement. As a result the net loss charges will not be available to support the revenue adequacy of CRRs, as originally proposed in the CAISO's July 2003 filing.
8. Another theme discussed extensively in the stakeholder meetings has been simplicity. It should be noted, however, that the dominant opinion among stakeholders seems to be to prefer that allocation of CRRs reflect LSEs' exposure to congestion charges, even if that means a more complex process. The CAISO has therefore developed its proposal to strive for simplicity, but within the objective of allocating to LSEs to hedge congestion exposure.

3.1.2 Objectives of CRR Allocation

The problem is to develop a set of CRR Allocation Rules that will apply to Load Serving Entities (LSEs) on behalf of customers they serve within the CAISO control area. Previous white papers on this subject and discussions with stakeholders over the last few months referred to a basic underlying principle of CRR allocation:

> Parties who support the embedded costs of the ISO transmission grid are entitled to an allocation of CRRs in accordance with the nature and extent of their support for these costs.

In addition, a number of objectives of CRR allocation were articulated, with the recognition that there would need to be some trade-offs in balancing these objectives:

1. (a) Where CRR entitlement is based on use of the grid to serve load, CRR allocation should be reasonably consistent with each entity's actual or expected use of the ISO grid.

   (b) Where CRR entitlement is based on investment in new transmission that is not recovered through access charges, CRR allocation should be consistent with the transmission sponsor's net addition of capacity to the ISO grid. This objective is addressed in the CAISO's proposal for allocating CRRs to sponsors of merchant transmission projects, and is not discussed further in this document.

2. CRR allocation should lead to CRR revenue adequacy. In practice this will be assured through application of a simultaneous feasibility test (SFT) as the central mechanism for determining which CRRs can be released.
3. CRR allocation should reasonably be based on market participant choice.
4. CRR allocation should promote maximal allocation of the congestion rents collected by the ISO to parties receiving the CRR allocation.
5. Any reductions in parties' requested CRR allocations should be performed in an equitable fashion, consistent with the priorities associated with their respective CRR entitlements and, only secondarily, reflective of their relative effectiveness in relieving transmission constraints.
6. CRR allocation rules should strive for simplicity, for example, with regard to the activities that must be performed by market participants and the CAISO in each annual and monthly CRR allocation process to develop and validate CRR requests.

These objectives have been discussed with stakeholders throughout this process, and the stakeholders are generally supportive of these objectives.

In addition to these objectives, the CAISO has noted the need to consider how CRR allocation rules could affect the incentives for investment in new transmission and generation infrastructure, to ensure that the CRR rules are consistent with these broader objectives. The issue, then, is to develop CRR Allocation Rules in accordance with the basic principle that achieve an appropriate balance of the stated objectives.

3.1.3 Structure of the CRR Allocation and Auction Process

The CAISO will conduct two CRR release processes – annual and monthly – each of which will release CRRs applicable to two Time of Use (TOU) periods, the conventional 6-by-16-hour Peak Period and the Off-peak Period comprised of all other hours of the week. The annual CRR structure will consist of eight sets of CRRs representing four seasons[11] and the two on-peak and off-peak TOU periods. Each CRR release process will consist of two major steps, a CRR Allocation Process and a CRR Auction. Participation in the allocation process will be limited to those entities eligible for an allocation of CRRs. Participation in the auction process will be open to all parties qualified with respect to creditworthiness requirements. Within each CRR release process (i.e., annual and monthly), the allocation process will be conducted and completed prior to the auction process.

Because the CRR allocation process is founded on a principle of eligibility, it is necessary to define the parameters of that eligibility, specifically the maximum quantities of CRRs to which each eligible party is entitled, and the allowable sources and sinks they may specify for the CRRs they wish to receive. With regard to maximum quantities, each LSEs annual eligibility, i.e., the maximum MW CRR quantity it can request for allocation in the annual allocation process, will be calculated separately for each season and TOU period and each LAP in which the LSE serves load. In each case the annual eligibility will equal 75 percent of the 99.5 percentile point on its historical load duration curves for that season and TOU period, with appropriate adjustment to reflect any migration of retail load from one LSE to another. The annual allocation process will therefore require an entire year's historical hourly load data, from which will be calculated a set of eight seasonal/TOU historical load duration curves for each LAP in which the LSE serves load.

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[11] The definition of the seasons may follow standard WECC usage, or may be adjusted somewhat to better align with seasonal factors specific to California. The CAISO will address this matter in the course of developing Business Practice Manuals early in 2006.

The monthly allocation process will use forecasted load rather than historical load, and will set the LSEs monthly eligibility to equal the 99.5 percentile point on the applicable monthly/TOU forecasted load duration curve, and its eligibility for monthly CRRs will equal its monthly upper bound minus its allocation of annual CRRs for that month.

With regard to allowable sinks, LSEs serving load within the CAISO control area will be settled at the applicable Load Aggregation Point (LAP) in the CAISO spot markets, and therefore the LAP would be the appropriate sink for allocated CRRs.[12] In case the LSE serves load in more than one LAP, there would be independent CRR allocations to that LSE for each LAP, each with its own MW upper bound calculated as described above based on load duration curves for each LAP. With these parameters of the CRR allocation structure specified, the major open question at this time is the specification of eligible sources for LSE CRR requests, which is the primary focus of the next section.

The annual CRR allocation process will make 75 percent of the grid's transfer capacity available in the network model used in the Simultaneous Feasibility Test (SFT). The annual allocation process will use an "all lines in service" assumption regarding the availability of grid facilities.[13] The monthly CRR allocation process, conducted prior to the start of each Trading Month, will allow LSEs to request CRRs for up to 100 percent of their eligibility for the Month/Time-Of-Use period minus their awarded annual CRRs, and will make 100 percent of the grid's transfer capacity available in the SFT. The network model for the monthly CRR allocation process SFT will, however, account for planned transmission outages and derates.

Multi-point CRRs. The CAISO will allow parties to request multi-point CRRs (MPT-CRR), a feature that was described in the July 2003 filing under the name "network service CRR" (NS-CRR). The CAISO now proposes to adopt the term MPT-CRR to avoid any potential confusion with other more conventional uses of the term "network service" in the electric utility industry.

All CRR release processes appropriately account for Transmission Ownership Rights (TOR), Existing Transmission Contracts (ETC), Converted Rights (CVR) and CRRs that are allocated to sponsors of Merchant Transmission projects. These matters are not the focus of the present section and are not discussed further here, nor is the matter of CRRs for LSEs serving load outside the CAISO control area.

3.1.4 Specification of Source Locations for LSE CRR Requests

This section assumes that each LSEs customer base is specified and there is no load migration through retail access. Modifications for retail access migration are covered in the next section.

This proposal utilizes the principle of grandfathering as a way to provide year-to-year continuity and certainty for LSEs, to support long-term contracting and generation investment. In such a system it is necessary to handle the first year differently from subsequent years. In the proposal described below the "end state" (i.e., for all years after the first year) annual allocation process is structured in three tiers where the first tier is for CRRs that were awarded in the previous year and are requested for renewal by the LSE (i.e., grandfathered), and the subsequent tiers are for LSEs to request CRRs that they do not currently hold, to obtain CRRs from new generation sources and to account for load growth. By sequencing the re-allocation of grandfathered CRRs ahead of the allocation of new CRR requests, the process maximizes the likelihood that LSEs'

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[12] Although the MRTU markets will utilize three large LAPs in Release 1, the present proposal is not tied to any specific number of LAPs and will be workable even if more granular LAPs are adopted.

[13] The CAISO may make an exception to the "all lines in service" assumption in situations where there is known to be a transmission outage or derate that could significantly affect CRR revenue adequacy during the relevant period.

grandfathered requests will remain simultaneously feasible from year to year. The end-state monthly process will not have grandfathering, however, and therefore needs only two tiers.

Under the proposed grandfathering process, the LSEs portfolio of “grandfatherable” CRRs can evolve over time in response to changing needs, or can remain constant over multiple years provided it comprises no more than 33.3 percent of the LSEs annual eligibility in year 2 of MRTU, and no more than 66.7 percent in year 3 and thereafter, and the LSE has not lost load on net due to retail access migration. To receive the grandfathering priority the LSE is not required to have received the CRR in the initial year; any newly allocated CRR will be eligible for grandfathering in the next annual process.

In each tier of the various allocation processes the CAISO will run a SFT to allocate a certain share of each LSEs’ maximum allocation. Between tiers (SFT runs) the CAISO will provide the results to LSEs to enable them to consider these results in deciding what additional CRRs to request in the next tier. By running separate, sequential SFTs for each tier, the tier structure enables LSEs to maximize their chances of receiving the CRRs they value most.

First Year Annual and Monthly Allocation Processes

In the first-year annual allocation CRR source nominations for Tiers 1 and 2 will require CAISO verification, whereas nominations for Tier 3 will be open to LSE choice. The LSEs maximum Tier 1 and Tier 2 allocations will be 50 and 75 percent, respectively, of its annual eligibility. These tier percentages mean that verification will be required for up to 75 percent of a LSEs CRR nominations in the annual CRR allocation process. Since the annual allocation will provide at most 75 percent of the LSEs combined annual and monthly eligibility for any given month, the 75 percent limit in Tiers 1 and 2 of the annual process translates to 56.25 percent of the LSEs combined annual and monthly eligibility that will be verified for the annual process.

The verification process will involve demonstration that the LSE had an entitlement to take energy to serve its load from the nominated sources during a historical reference period. Verified sources may include generation owned by the LSE or under contract, as well as trading hubs (which will correspond to today’s congestion zones) used for delivery of bilateral energy contracts.[14] For the purpose of source verification short-term energy contracts of at least one-month duration will be acceptable.

An additional rule in the annual allocation process will be to limit the CRRs requested from a particular generation source to 75 percent of the P-max of the generator, even if that generator is owned or fully contracted to the requesting LSE. The reason for this is that the combination of nominating CRRs up to 100 percent of generator capacity but only making 75 percent of the transmission system available could cause generation pocket constraints to be binding in the annual allocation, even though these constraints may not bind when the full network capacity is available. Once one of these constraints becomes binding in the SFT all CRR requests that affect it would be prorated.

The first-year monthly process will be essentially the same as the annual process, except for (1) basing the total monthly eligibility on forecast load rather than historical load; (2) having two tiers rather than three; (3) adjusted percentages involved in “truing-up” each LSEs CRR quantity to 100 percent of its full monthly eligibility; (4) increasing grid facility and generator P-max values to 100 percent; and (5) incorporating planned transmission outages and derates into the network model for the SFT.

[14] In addition there may be some situations for holders of Existing Transmission Contract (ETC) rights where the contractual rights to transmission service do not extend all the way to the load location. In such cases the ETC holder would need CRRs whose source is the terminus of the ETC rights and whose sink in the relevant load location.

The annual CRR release will be structured as a set of four seasonal CRR allocations. Thus the LSE Upper Bounds will be calculated for each season and TOU period. The following points describe the features of the proposed first-year annual allocation process, as applied to each season/TOU period and each LAP in which the LSE serves load. The CAISO proposes a three-tier annual process, with tier limits equal to 50, 75 and 100 percent of each LSEs annual eligibility. The relatively smaller tiers 2 and 3 allow LSEs to adjust their CRR holdings in small increments as the 75 percent of system capacity allotted to the annual process becomes more fully accounted for by released CRRs and some constraints begin to bind.

An important element of the CAISO CRR allocation methodology is the "historical period" for verification of CRR sources. The historical period is a year in the recent past, as recent as possible consistent with LSEs not having strategically modified their supply procurement practices in anticipation of CRR allocations. It is therefore proposed that the historical period be 9/1/04 to 8/31/05.[15] The verification rules described below would apply to the LSEs supply portfolio on a season-by-season basis for the annual allocation and on a month-by-month basis for the monthly allocation. The verification for a particular seasonal period would be based on the LSEs supply portfolio on the 15th of the 2nd month in the seasonal period, and the verification for a monthly CRR period would be based on the LSEs supply portfolio on the 15th of the corresponding month in the historical period.[16]

Eligible sources in Tiers 1 and 2 would include the following. All categories of sources will be given equal weight in the SFT for Tiers 1 and 2. Eligible sources within the CAISO:

- Up to 75% of generator Pmax *LSE ownership share of an internal generating unit owned during the historical period. LSE must provide proof of its ownership share. (Category I/O)
- Up to the contract quantity of capacity (MW) for any internal generator whose energy has been purchased by the LSE for the historical period under a contract with a term of one month or more, not to exceed 75% of generator Pmax. The LSE must provide information substantiating the existence of the contract. (Category I/C)
- Up to 75% of average hourly quantity contracted for physical delivery at a trading hub during historical period under a contract with a term of one month or more (SP-15 or NP-15). The LSE must provide information substantiating the existence of the contract. (Category TH)
- For the special case of ETC holders noted above, up to 75% of the share of the ETC holder's load that is served under an ETC that does not provide transmission service all the way to the ETC holder's load location. (Category ETC)

Eligible sources external to the CAISO:

- Up to 75% of generator Pmax *LSE ownership share of any generating unit outside the CAISO control area owned by an LSE for the historical period, for which there was firm transmission to the border of the CAISO control area for the historical period. In this case the source point for the CRR nomination would be the relevant intertie scheduling point. (E/O)
- Up to the contract quantity of capacity (MW) for any generator outside the CAISO control area whose energy was purchased by the LSE for the historical period under a contract with a term of one month or more, for which there was firm transmission to the border of the CAISO control area for the same period, not to exceed 75% of generator

[15] The final specification of the historical period may be shifted slightly to be consistent with the final definition of seasons that is adopted.

[16] Using the midpoint of the season or the month as the verification date for a contract is intended as a device to assign short-term contracts unambiguously to the appropriate season or month.

Pmax. In this case the source point for the CRR nomination would be the relevant intertie scheduling point, assuming that is the contract delivery point. (E/C)

- Up to the LSEs share of residual import capability at each CAISO intertie in the annual allocation. All LSEs would receive shares of the residual import capability of all interties regardless of the actual locations of their loads. This mechanism allows all LSEs to obtain shares of CRRs sourced at the intertie scheduling points even if they don't have verified import sources in the first-year allocation process. The residual import capability for an intertie will be defined as 75% of the rated import capability for the intertie, minus 75% of the TOR and ETC rights originating at the intertie scheduling point, and minus the total source eligibility determined for the intertie for the season/TOU in the previous two paragraphs, based on LSE generation ownership and contracts (E/O, E/C). A percentage of the residual import capability will be allocated to LSEs in proportion to their loads. LSEs are then eligible to nominate CRRs up to this quantity. This step will allocate less than 100 percent of the residual import capability, however, to allow some import capacity to be procured in the auction process. (E/R)

All Tier 1 and 2 nominations will sink at the LAP. The SFT will be applied at the LAP level, i.e., CRRs will be defined to sink at the LAP along the lines of Sensitivity 5 in CRR Study 2.

In Tier 3 there would be no restrictions on eligible sources and no verification of sources. The LSE can choose to nominate CRRs that sink at either the LAP or at sub-LAPs, where the definitions of the sub-LAPs will be specified on the basis of a future CRR study but are expected to be similar to the sub-LAPs used in CRR Study 2. CRRs awarded to sub-LAPs will settle at sub-LAP prices, as in Sensitivity 7 in CRR Study 2. Tier 3 will allow LSEs to obtain partial hedges for the portion of their load that is not hedged by CRRs sinking at the LAP. Some additional CRRs may be feasible to sub-LAPs that are not feasible to the LAP.

The monthly process will differ from the annual process by having only two tiers, raising grid facility and generator P-max values to 100 percent, and incorporating planned transmission outages and derates into the network model for the SFT. The first tier will account for 50% of the LSEs incremental monthly eligibility and will need to be sourced from verified sources. The second tier will account for the remainder of the monthly eligibility and will not restrict the choice of sources. Combining the verification tiers from the annual and monthly process, the result is that up to 68.75% of the LSEs total awards for any given month could be from verified sources, assuming that the LSE nominates the maximum quantities in the validated tiers and all of these nominations are awarded.

End-state Annual and Monthly Allocation Processes

After the first year, in the end-state allocation processes there will be no source verification by the CAISO.[17] There will be three tiers in the annual process and two tiers in the monthly process, where each tier involves a distinct SFT run followed by an opportunity for LSEs to review their results in formulating their requests for the next tier. Tier 1 of the annual process allocates only grandfathered CRRs that the LSEs want to renew. Tier 2 provides an opportunity for LSEs that gained load through retail access migration to obtain new CRRs with some priority over new CRR requests, as described further below. Tier 3 then allows all to request CRRs that they did not hold in the current year and to nominate up to their annual eligibility. The tiered structure enables LSEs to request their most desired CRRs first when the likelihood of receiving their full nomination is relatively high, and to see the results before submitting their requests for the next tier. Beyond the first tier of the annual process there is no requirement that source

[17] To be clear, the CAISO does intend to limit CRR source locations (and also sink locations in the auction processes) to those network nodes or locations that are used for scheduling in the Day Ahead market.

nominations be from the grandfathered CRRs, and there is no priority given to nominations to renew CRRs. In particular, there is no grandfathering at all in the monthly allocation process.

For the tiers of the annual process the LSE requests would have to observe the following limits. These limits are based on the assumption that the annual process allocates 100 percent of the LSEs annual upper bound for each season/TOU period, calculated as described earlier based on the set of eight seasonal/TOU load duration curves. At the first grandfathering opportunity (i.e., year 2 of MRTU) the amount of grandfathering will be more limited than in subsequent years, hence there are two different expressions below for the Tier 1 Upper Bound.

- Tier 1 Upper Bound (Year 2) = lesser of (33.3% of annual upper bound) or (annual CRRs allocated in the previous period minus any reduction for net loss of load due to retail access[18]).
- Tier 1 Upper Bound (Year 3 and beyond) = lesser of (66.7% of annual upper bound) or (annual CRRs allocated in the previous period minus any reduction for net loss of load due to retail access).
- Tier 2 Upper Bound = greater of zero or (50 percent of annual upper bound minus Tier 1 allocations), plus 50% of net load gain due to retail access (if positive).[19]
- Tier 3 Upper Bound = greater of zero or (100 percent of annual upper bound minus Tiers 1 and 2 allocations), plus 100% of net load gain due to retail access (if positive).

For example, consider a case where there is no retail access migration (an example of retail access migration is provided in the next section). Suppose the LSEs annual upper bound is 100 MW, and in the first year it received 60 MW of CRRs in the annual allocation process. In the second year this LSEs load has remained the same so its annual upper bound is still 100 MW. Then in Year 2 it can nominate up to 33.3 MW of its first-year annual CRRs for grandfathering. Assuming it receives all of these in Tier 1, then in Tier 2 the LSE can nominate up to 16.7 MW of CRRs, which could be made up of previously awarded CRRs or new CRRs. In Year 3, using the same numbers, in Tier 1 the LSE can nominate up to 60 MW of the annual CRRs it was allocated in Year 2. If it receives all of these in Tier 1, then in Tier 2 it is not eligible for any additional CRRs because its Tier 1 award exceeds its Tier 2 Upper Bound.

For the end-state monthly process there will be no grandfathering and therefore only two tiers are needed, with percentages the same as in the first-year monthly process.

3.1.5 Accommodating Retail Choice

Migration of retail choice customers between LSEs needs to be accommodated in the CRR process in three ways: (1) adjustments to the prospective annual allocation, (2) adjustments to the prospective monthly allocation, and (3) mid-period adjustments with respect to current-period CRR holdings. In theory the mid-period adjustments are of two types: adjustments with respect to current-period annual CRRs based on the point in the annual cycle when the load migration occurs, and adjustments with respect to current-period monthly CRRs based on the point within the monthly cycle when the load migration occurs. In practice, however, the value of current-period monthly CRRs associated with retail access load migration is expected to be small unless there is a significant expansion of retail choice, and therefore the CAISO proposes not to require any adjustment between LSEs for holdings of monthly CRRs.

For the annual and monthly prospective adjustments ((1) and (2)), the proposal is to reduce the quantity of an LSEs CRR holdings eligible for the grandfathering priority in proportion to the

[18] Adjustments to grandfatherable CRRs for loss of load due to retail access migration are discussed in the next section.

[19] Adjustments to Tier 2 and 3 upper bounds for net retail access load gain are discussed in the next section.

share of its load that migrated away to other LSEs. Note, however, that due to the quantity limits on grandfathering this adjustment will only have an impact when a LSE has lost a large share of load. For mid-period adjustments the CAISO will require a financial payment from the LSE losing customers to the LSE gaining the customers, to be calculated as described below. The two LSEs can accomplish this via transfers of CRR holdings through the CAISO's secondary registration system (SRS), but the CAISO will not require the parties to use this system. In this discussion the assumption is that total load in the system is essentially fixed so that we can focus on changes to each LSEs total eligibility due only to customers switching between LSEs, without any effect of overall load growth.

The rules discussed here apply only to the end-state annual allocation process, obviously, since there is no grandfathering the first year. In the annual allocation the CAISO proposes to reduce a LSEs grandfatherable CRR source quantities in the next annual allocation in proportion to the net load lost through retail choice migration since the last annual allocation. The reduction will be applied as a constant percentage to all of the CRR sources that were awarded in the annual allocation prior to the LSE losing load. In the next annual process, the Tier 1 SFT will include all LSE nominations to renew their current, grandfatherable annual CRR holdings (up to the reduced maximum quantities for LSEs losing load) plus CAISO "reservations" for the annual CRRs that were part of the current year holdings of LSEs losing load but due to load migration are no longer grandfatherable by those LSEs for the next year. These CRR reservations are used only for the purpose of equitably prorating grandfathered CRRs if necessary, as a means to ensure that sufficient transmission capacity is reserved in Tier 1 to open up capacity in Tier 2 to enable LSEs gaining load to obtain new CRRs for the load they gain from LSEs losing load. Thus, there is no requirement for a LSE to take the CRRs given up by the LSE whose load migrated, and once Tier 1 is done these CRR reservations are erased for running Tiers 2 and 3.

One additional feature helps to ensure that LSEs gaining load through retail choice can obtain sufficient CRRs for their load. Rather than raising the overall CRR nomination cap for the LSEs with net gains in load, there would be a separate nomination cap for the gain in load. Thus, if an LSE gained 10 MW of load, it would have a separate Tier 2 nomination for 5 MW of CRRs and another 5 MW CRR nomination cap in Tier 3. LSEs gaining load would thus have a preferential chance to acquire CRRs using the transfer capability freed up by the release of CRRs by the LSEs that lost load. This approach also serves to make any transfer capability freed up by release of grandfathered CRRs or other changes in LSE nominations available to all LSEs who have grandfathered CRRs covering less than 50 percent of their load.

In the monthly allocation there is no grandfathering, so there is no affect to the LSE losing load except through a reduction in its load forecast and hence its monthly eligibility for future monthly cycles. Analogously, the LSE gaining net load would see an increase in its load forecast and its monthly eligibility for future months.

Regarding mid-period adjustments, the CAISO proposes no requirement for the transfer either of holdings of monthly CRRs or of the value of monthly CRRs for the remainder of the current month. During the discussion at the stakeholder meetings it was suggested that the mid-month adjustment would in most cases be small enough to be ignored, which would allow for a simpler adjustment process for retail access. With respect to holdings of annual CRRs, however, the CAISO believes that the associated value should not be ignored, and therefore will require an appropriate transfer to take place. In addition the CAISO will allow, but not require, parties to utilize its Secondary Registration System (SRS) for affecting this transfer. The SRS provides an effective, straightforward mechanism for implementing the principle stated in the CAISO's July 2003 filing that CRRs will "follow the load" when retail customers migrate from LSE-A to LSE-B.

The proposal is best illustrates with an example. If LSE-A loses five percent of its load through migration to LSE-B at a particular point during the annual CRR cycle, it must transfer five percent of the remaining value of its allocated annual CRR holdings to LSE-B. To be precise, the remaining value of its annual CRR holdings is equal to the hourly CRR payment stream starting on the date the customer migration became effective and ending on the date the annual CRRs expire. This transfer of value can occur through direct financial payments between the relevant parties, outside of the CAISO settlement system. Alternatively, parties can utilize the CAISO's SRS to register a transfer of a share of LSE-A's CRR holdings, which would need to be spread as a uniform percentage over all of LSE-A's sources associated with the same LAP in which the migrating load is located, to LSE-B. The transfer would be for the remainder of the current annual CRR cycle and must include both peak and off-peak CRRs. To be accepted by the SRS the transfer must be entered by both parties into the SRS to take effect on the same date as the load transfer takes effect. As a result of entering the transfer into the SRS, the CAISO's settlement system will route the hourly settlement for the transferred CRRs to LSE-B instead of LSE-A. If the parties opt for financial settlement rather than a transfer of CRRs from one LSE to another, that settlement should be equal in value to the revenue stream that would have accrued to the corresponding transfer of CRRs through the CAISO's SRS. It must be noted that this value cannot be known in advance, however, because it depends on the hourly prices that will be determined in the CAISO's day-ahead market.

When there is growth in a LSEs total load that is not the result of retail access load migration, it will be reflected in the forecasted load duration curves used to calculate the LSEs MW upper bound for CRR allocation. When the next period's MW upper bound increases due to load growth, the LSE will be able to request additional CRRs beyond the quantities it held in the prior period in the later tiers of the allocation process.

A final issue remains regarding the sale or transfer by a LSE of CRRs it was allocated. The CAISO's July 2003 filed proposal stated that allocated CRRs would actually be the property of the customers rather than the LSEs, i.e., that the LSEs would be viewed as custodians of these CRRs on behalf of customers, and as a result it would not be appropriate for LSEs to sell their allocated CRRs either in the CAISO's auction processes or in the secondary market. The CAISO now believes that this restriction is not necessary, given the proposed rules for adjusting each LSEs allocation eligibility, supplemented by financial settlements between LSEs when customers migrate from one LSE to another. The CAISO believes that the proposal described in this white paper adequately protects the interests of customers without restricting LSEs from selling allocated CRRs. The CAISO therefore proposes to remove this restriction in the interest of facilitating greater liquidity in the CRR auctions and secondary market.

Although the CAISO proposes to eliminate the rule that prohibits LSEs from selling allocated CRRs, the software functionality to accommodate sales of CRRs by auction participants may not be available in Release 1 of MRTU. This functionality does exist within the vendor's software system and will be considered for Release 2, but the current scope of work for the CRR project does not include this feature because the CAISO expected to retain the prohibition on sales of allocated CRRs. Parties will still be able to sell CRRs through bilateral transactions that they record in the SRS. In addition they can accomplish essentially the same thing as a sale in the auction by bidding to buy a CRR in the opposite direction of the one they want to sell. Thus if LSE-1 wants to sell a CRR from source X to sink Y, the equivalent transaction would be to bid to buy a CRR from source Y to sink X. As a result of this purchase LSE-1 would hold both an X-Y and a Y-X CRR. The values of these two CRRs would net exactly to zero, leaving LSE-1 in the same position financially as if it had sold its X-Y CRR. The CAISO therefore believes that this small limitation should not be a problem.

3.2 CRR Allocation for Load Outside the CAISO Control Area

The issue is whether to allocate CRRs to LSEs on behalf of load outside the CAISO control area in a manner analogous to LSEs serving load inside the control area.

The CAISO proposes to offer to LSEs with external load – upon demonstration of a legitimate need, described further below – the opportunity to request CRRs through the same allocation process the CAISO performs for LSEs with internal load, in exchange for pre-paying the access charge for the period for which the requested CRR is valid. LSEs will thus be able to request CRRs through the annual and monthly on-peak or off-peak CRR allocation, in one-MW increments, in exchange for pre-paying one MWh access charge times the number of hours in the relevant period, for each MW CRR requested.[20]

Payment of the annual (monthly) access charge for one MW entitles the entity to request one MW CRR in the CAISO's annual (monthly) CRR allocation process. Because the CRR allocation process enforces a simultaneous feasibility test (SFT) there is some chance that the entity will be allocated fewer than the full amount of requested CRRs for which it pre-paid. In this case the CAISO proposes to refund to that LSE, at the end of the year (month) to which the CRRs apply, that portion of the amount paid for the unawarded CRRs that was not used up by the LSE in access charges incurred over the course of the period (see example later in this document).

In determining a party's "legitimate need" to participate in this allocation process, the CAISO will consider generation facilities within the CAISO control area that are owned or under contract to the LSE serving external load.

The CAISO will apply a MW upper bound to the amount of CRRs a LSE with external load can request in this process, analogous to the MW upper bound that will apply to LSEs with internal load. That is, the LSE with external load will have to provide data to the CAISO from which can be calculated that LSEs hourly use of the CAISO grid to export power. The data will have to cover a full year if the LSE wants to participate in the annual allocation process. If the LSE only wants to participate in a monthly allocation process, the LSE may submit historical data for the same month in the previous year.

LSEs that serve load outside the CAISO control area have argued that they should be allocated CRRs in a manner analogous to LSEs serving load inside the control area. They argue that, like the LSEs with internal load, they also support the embedded costs of the CAISO grid through payment of access charges and will be exposed to LMP-based congestion charges for using the grid when MRTU is implemented. Some of these parties refer to a FERC ruling on ISO-NE to support their argument.

Other parties argue that LSEs with external load are differently situated to LSEs with internal load – specifically they have the ability to choose whether or not to use the CAISO grid to serve their load – and therefore should not be entitled to CRR allocation.

The CAISO's proposal is based primarily on the rationale that external loads and internal loads are differently situated with respect to their need to rely on the CAISO grid and, as a result, the certainty of their future payment of CAISO access and congestion charges is very different. Additionally, the CAISO's proposal is consistent with provisions approved by FERC for PJM, ISO-NE and MISO.

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[20] Based on the CAISO's current Wheeling Access Charges (WAC), the per MW cost for a full year (both on-peak and off-peak hours) will be in the range of $22,000, based on an average WAC of approximately $2.50/MWh. The CAISO will release distinct CRRs for on-peak and off-peak hours based on the usual 6 x 16 definition of the on-peak hours of the week. The cost for on-peak hours only would be roughly $12,500 per MW per year, and the cost for off-peak hours roughly $9,500 per MW per year. The CAISO notes that the cost of a full year's access charge cannot be known exactly at the beginning of the year because the access charge may need to be adjusted and revised during the year to ensure accurate and complete recovery of the Participating Transmission Owners' revenue requirements over the year. Therefore at the end of the year the CAISO may need to charge or refund to the LSE who participates in this offering any discrepancy between the actual full year's access charge and the per MW prepayment amount.

3.3 CRR Allocation for Sponsors of Merchant Transmission Projects

Currently the costs for building new upgrades or additions to the CAISO Controlled Grid, either by the PTOs or by merchant transmission entities, are recovered by either (1) rolling into PTO access charges, (2) receipt of FTRs, or (3) reimbursement over a period of time for the full amount of investment. After MRTU implementation, the CAISO intends to make available CRRs to developers of new transmission facilities that do not have alternative methods for recovery of their upfront network upgrade costs. The issues under consideration here involve the principles for allocation of CRRs to entities who build new or upgrade existing ISO grid facilities and the CAISO's methodology for determining the amount and spatial configuration of CRRs to be allocated to these entities, including those entities who have already constructed new facilities and seek to convert their FTRs to CRRs.

The CAISO proposes to allocate this type of Merchant Transmission (MT) CRRs for the incremental amount of transfer capability when the new facilities are put under CAISO operational control and energized. Thus, the entitlement of CRRs would be based upon the impact on the total capacity of the CAISO grid.

The CAISO proposes these MT CRRs would remain in effect for the life of the facilities or 30 years, whichever is less, but this structure could be reviewed if the upgraded path utilized were de-rated on a long-term basis. The CAISO proposes the MT developer may choose the nominated MT CRRs to be either Options or Obligations. However, the CAISO proposes that merchant transmission sponsors must accept counter-flow CRRs to mitigate the reduced feasibility of CRRs previously awarded to other entities, so that these previously awarded CRRs would remain protected throughout their remaining term.

The CAISO also has outlined a proposed methodology for determining the incremental amount of transfer capability that would be the basis for the amount of MT CRRs to be allocated. This methodology is based largely on PJM's process for allocating Auction Revenue Rights.

The CAISO recognizes that MT CRRs potentially offer important incentives for transmission expansion, and the CAISO is receptive to further stakeholder input that would improve this framework for these allocation rules. The CAISO's Market Surveillance Committee (MSC) also is reviewing this issue and will be able to offer further analysis to shape this proposal and frame a better understanding for all market participants.

While this proposal has been discussed with some stakeholders to some degree, the CAISO is not confident that it has fully vetted all the issues and concerns regarding CRRs for MTs. While it is committed to having MT CRR provisions at the start of MRTU in February 2007, the CAISO believes it is not imperative that the CAISO hurry resolution of these issues prior to the November 30, 2005 filing of the MRTU Tariff. Rather, with respect to this specific aspect of CRRs, the CAISO believes it is possible to include general tariff language related to the availability of MT CRRs in the planned November 30th tariff filing, without foreclosing a wide range of parameters for MT CRR allocation rules or impacting the MRTU implementation schedule. In the meantime, and subsequent to the November 30th filing, CAISO will continue to work towards resolution of the issues with its stakeholders.

Therefore, the CAISO proposes to continue to engage with stakeholders in further review of this MT CRR proposal after the September 20-22 MRTU stakeholder meeting and even after the November tariff filing to better define the principles for allocating MT CRRs. The CAISO notes that the timing of this process does not impede or in any way affect the CAISO's ability to file complete CRR allocation rules for LSEs in the November 30 tariff filing.

The following comments were offered recently to the CAISO regarding this proposal:

Calpine supports merchant transmission developers having a choice between the current monetary reimbursement mechanism and the allocation of CRRs. In response, the CAISO has previously stated its intention to phase out the monetary credit-back mechanism with MRTU implementation, but this position could be reviewed in the context of the timing for the MT CRR allocation.

FPL has raised concerns about the treatment of merchant transmission projects currently in operation, and the transition of their awarded FTRs to CRRs. The CAISO will explore ways to respond to these concerns.

SCE raises concern that the 30-year award of CRRs could impact other CRRs awarded to LSEs through load growth or other changes after the initial determination to merchant transmission developers. SCE also points out that queuing MT upgrades based on their operating date differs from the CAISO's generator interconnection process that is based on receipt of a valid interconnection request. These are valid issues that the CAISO and stakeholder should consider further.

Finally, SCE favors deferral of this MT proposal until after the planned November 30 FERC filing to allow more extensive stakeholder review. The CAISO largely agrees but emphasizes its intention to work quickly with stakeholders before and after the November filing date.

3.4 Issues Related to Existing Transmission Contracts (ETCs)

Following an extensive stakeholder process in 2004, the CAISO filed and FERC approved a conceptual proposal for the treatment of ETCs under MRTU. The proposal resolved how ETCs would be scheduled, validated and settled under LMP. Certain issues were deferred to the current stakeholder process for MRTU tariff language. These include the following:

- Treatment for Losses on ETC Schedules
- Treatment of Charges other than Congestion or Losses
- Validation Issues
- Inter-SC Trades for ETCs
- Resale of ETC Rights

These issues and CAISO’s solution and relevant stakeholder comments are summarized below.

Settlement Treatment for Losses on ETC Schedules

Under the July 2003 MRTU filing, the over-collection of marginal loss revenues in the Day-Ahead would be paid to the CRR Balancing Account and used first to offset revenue deficiency to CRR holders. The annual balance in the CRR Balancing Account would be paid to the PTOs resulting in reduction of their access charges. Although FERC has approved ISO’s proposal, since ETCs are not beneficiaries of access charge reduction, they have objected to this procedure.

The CAISO has proposed a new procedure to allocate marginal loss surplus to Metered Demand. Under the new proposal, all Scheduling Coordinators will be charged for Marginal Losses under LMP, and the surplus would be distributed to all loads and exports according to the revised mechanism described in a later section. Under this new mechanism ETC holders who serve as SCs for ETC schedules would receive a portion of the net loss revenues, just like other SCs who represent loads and exports. The ETC contract parties would resolve among themselves who is responsible for paying losses and the CAISO would stay removed from interpreting these contracts or favoring contract parties.

The proposed solution addresses the ETC stakeholder concerns.

Settlement Treatment on Charges other than Congestion or Losses

Some ETC holders have sought clarification about what charge types would or would not apply to ETC schedules. Parties have requested a list of all existing settlement charge types and the expected charge types to be applied after MRTU implementation.

For this Proposal, the CAISO clarifies its intention to exempt valid ETC schedules after MRTU implementation from these specific settlement charges:

- Congestion charges, which would be perfectly reversed.
- Access Charges, consistent with the current practice.
- In addition, stakeholders should note that the structure of the Grid Management Charge under MRTU would be determined in a stakeholder process in 2006. Presumably the congestion management bucket of the GMC will change with the introduction of LMP for congestion management.

The CAISO proposes that all other charges under MRTU would apply to ETC schedules, which is consistent with current practice.

The stakeholders have requested that the CAISO provide a complete description of its charges to ETC holders so that they may judge whether they should be paying for these charges under the ETCs.

The CAISO does provide complete information to anyone who is paying the CAISO charges. The CAISO supports equitable assessment of charges upon all Scheduling Coordinators.

ETC Validation

The ETC conceptual filing on the CAISO's expected treatment for ETCs relies upon the PTOs to provide data files so the CAISO can automatically confirm that ETC schedules and schedule changes are within their contractual parameters. Several stakeholders have requested further clarifying details about the ETC validation process.

The CAISO offers the following clarification of the policies that are guiding the implementation details for validating ETC schedules:

- For the CAISO, validation of ETC schedules entails an automatic process for verifying that submitted ETC schedules and schedule changes are within the contractual limits specified with regard to eligible injection and withdrawal locations, maximum MW quantities, scheduling deadlines and other relevant parameters.
- The PTOs will be required to submit ETC data files that contain information on these contract parameters, which can be automatically checked by the CAISO to verify that a submitted ETC schedule is valid, meaning the schedule is within the contract rights.
- The PTOs will be responsible for the accuracy of the data files related to the ETC schedules.
- The PTOs will provide identical copies of these data files ETC date file to the ETC rights holder whenever these data files are submitted to the CAISO.
- The CAISO is not a party to existing contracts and has no role in interpreting ETCs.
- The contract parties will resolve disputes involving these data files.
- In general the data files provided by the PTOs will be static because the contract parameters are not expected to change once it is established. If the previously established contract parameters change, the PTO will be required to submit an updated data file to the CAISO, with identical copies to the ETC holder.

- To ensure periodic review, the PTO will be required to submit ETC data files once a year to the CAISO, with identical copies to the ETC holder.
- The ETC data file also would contain a look-up table or a function that determines the maximum MW values in the event of changes in the Operational Transmission Capacity (OTC) for a specific Branch Group. This allows the CAISO to plug in the OTC value and automatically calculate the maximum allowable ETC MW.
- In the HASP, the CAISO will give valid ETC schedule changes priority over non-ETC day ahead schedules and HASP bids. Where the contract rights permit, the CAISO will allow valid ETC schedule changes after the submission of HASP schedules. The CAISO will, as necessary, redispatch non-ETC resources to accommodate valid ETC schedules.
- If an ETC self-schedule is not balanced, or if the ETC self-schedule exceeds its entitlement based on the current OTC, the ETC self-schedule would lose its scheduling priority and would be treated as an ordinary self-schedule. The ETC schedule would be charged congestion for its unbalanced part, but would receive the perfect hedge for that portion of the schedule that is within its contract rights.

Some stakeholders have maintained that the PTOs should provide the priorities, nomograms, charts or software programs related to ETC rights to the CAISO so the CAISO can properly treat the ETCs during de-rates or other system emergencies.

The CAISO supports the concept that the PTO data files should provide all necessary information to verify the proper treatment of ETCs when transmission capacity is reduced.

Inter-SC Trades for ETCs

The July 2003 MRTU filing proposed that PTOs schedule ETCs in the forward markets using Inter-SC trades at injection and withdrawal points defined in the contracts. Under this original proposal, where congestion costs would need to be allocated to the appropriate party, the Inter-SC Trade mechanism will facilitate tracking of charges and allocation of cost responsibilities. Since then the CAISO has changed the way ETCs are protected from congestion charges (by reversing their congestion payments) and restricted the settlement of Inter-SC Trades of Energy in CAISO’s markets in view of the seller’s choice settlement. This has created some questions regarding scheduling and settlement of ETCs (and TORs) in specific cases.

The scheduling issue related to ETC/TORs occurs when an ETC holder either (a) does not know the ultimate source or sink of an ETC/TOR schedule or (b) has contract obligations to transact at a specific location that is different than the LAP, Trading Hub or Generation Node contemplated under MRTU.

For the first issue (a), the CAISO believes it has provided a sufficient mechanism to schedule a source and sink utilizing an ETC/TOR by way of allowing different scheduling coordinators for the source and sink to schedule. To facilitate this, the ISO has designed multiple eligible sources and sinks defined in the Master File. Once these are defined in the Master File, the SIBR and IFM system will utilize such information in the ETC/TOR schedule validation process.

For the second issue (b), a bi-lateral transaction outside of CAISO markets would be necessary to schedule an ETC or TOR at a location that is different than the LAP, Trading Hub or Generation Node.

Because parties can settle up bi-lateral arrangements outside of the CAISO settlement system, the CAISO strongly encourages such arrangements where appropriate. The CAISO is greatly reluctant to expand the eligible nodes that SCs can perform inter-SC trades beyond the trading hub, LAP and generator node at this time.

The CAISO recognizes that some ETC holders may feel reluctant to open up their contract to incorporate an additional bi-lateral settlement. There also is risk that parties will not be able to agree on bi-lateral settlement outside of the CAISO. This risk is expected to be low since the parties will have agreed regardless as to what location they are going to schedule and transact at. If, however, this becomes an issue that cannot be resolved, the CAISO may be forced to create specific hubs to facilitate such trades. However, the CAISO will not be able to implement additional validation to prevent others from trading at special hubs. This may require after-the-fact compliance monitoring until such a validation could be implemented.

Many stakeholders who are not parties to the seller's choice contracts prefer to use the CAISO settlement system to settle their bilateral arrangements regardless of their contractual handoff locations. The CAISO design presently provides settlement services only for physical Inter-SC Trades and for Inter-SC Trades at the predefined hubs. Despite this limitation, the CAISO proposal stated above provides the facility to reverse congestion charges for ETCs.

Resale of ETC Rights

Currently the CAISO's expected treatment of ETCs under MRTU does not address the situation where ETC holders may sell their rights for use by another party. More specifically, the CAISO's expected treatment of ETCs does not provide capability to transfer the ETC identifier number from one SC to another. This means that if the ETC holder sells its rights, it must do so outside of the CAISO processes and the same SC must still schedule for the current user of the rights.

The CAISO's position has been and continues to be that it is not prepared to develop software or other protocols to accomplish the trading of ETC rights, because the CAISO is not aware of specific ETCs where there is a contractual ability to trade rights. If there were clear agreement among the parties to an ETC and a strong desire by parties to trade, the CAISO could explore developing the software to provide this functionality in a subsequent MRTU release. The required system would be something like the CAISO's Secondary Registration System (SRS) for the trading of FTRs and CRRs, which would track transfers between SCs of ETC scheduling rights and eligibility to receive the ETC congestion hedge, as well as changes to the eligible sources and sinks that can utilize the ETC rights. In addition, this new SRS-like functionality would require supporting data flows and validation rules. Such functionality cannot be implemented in MRTU Release 1.

As an interim measure, however, the CAISO may accommodate limited transferability of ETC rights be allowing the seller of the rights – i.e., the PTO who is responsible for providing the ETC validation data to the CAISO – to pre-declare an expanded set of sources and sinks associated with different scheduling coordinators in the Master-File. Once this set is defined, the any of the designated SCs would be able to submit schedules under the ETC rights and have these be accepted by the CAISO validation rules.

The CAISO suggests this option with some caveats, however. First, it is essential that both parties to the ETC confirm to the CAISO that such trading is allowed under the ETC rights and agree upon the eligible SCs and other data that is required for the Master File. This is consistent with the CAISO's proposed procedures for validating ETC schedules. Second, in the event that ETC rights are over-scheduled for any trading hour in any CAISO market due to the use of the same ETC by more than one SC, the entire ETC will lose its scheduling priority for that hour. The last provision is necessary to ensure that errors in ETC schedule submission do not result in adverse impacts on other market participants.

3.5 Transmission Ownership Rights

The CAISO generally defines a Transmission Ownership Right (TOR) as a right to utilize, for the purpose of electric transmission service, transmission facilities that are located within the CAISO Control Area but are either wholly or partially owned by an entity that is not a Participating Transmission Owner (PTO). At the July 13-14 stakeholder meeting, the CAISO put forth a White Paper (dated July 14, 2005) that described the TOR entities expected to be inside the ISO control area in February 2007 and explained how the CAISO modeled these facilities for the purposes of CRR Study 2. Since the July 13-14 stakeholder meeting, the CAISO has engaged with representatives of these TOR entities to review the July 14, 2005 White Paper, especially focusing on the modeling assumptions for CRR study purposes that are relevant for each entity.

Proposed Scheduling Treatment for TORs

The CAISO has proposed full capacity reservations for TORs at inter-ties and top scheduling priority for internal TORs, which is similar to the expected treatment for ETCs except that TORs would receive the highest scheduling priority.

- For TOR capacity on Control Area boundary interties that are modeled radially in the FNM, the CAISO would reduce the available transmission capacity of the intertie by the amount of the TOR. This effectively prevents scheduling by other CAISO market participants on the TOR capacity.
- For TOR capacity that is internal to the CAISO Control Area and modeled as part of the looped network, the CAISO will not set aside capacity on the facility, but will instead provide highest priority source-to-sink scheduling rights to the TOR holder. The source and sink points for such scheduling rights will be determined by the TOR holder and the CAISO, consistent with the TOR holder's rights, in a manner that ensures the ability of the TOR holder to fully utilize its rights.

The CAISO also proposes that the Scheduling Coordinator submit the relevant data files on each TOR facility upon which the CAISO can verify TOR schedules. These data files and the process for submitting them would be identical to data files for ETC validation.

Proposed Settlement Treatment for TORs

Generally, the settlement treatment for TORs under MRTU would be similar (but not identical) to the treatment of ETCs. The CAISO proposes the following settlement features for TORs:

- Full reversal of congestion charges through the “Perfect Hedge” mechanism.
- The Scheduling Coordinator for TORs would be charged for losses like Scheduling Coordinators for ETCs and other entities. This would include charges for the full marginal losses on transmission service between nodes, and a pro-rata share of the refunds associated with excess losses that are refunded for the period of each settlement statement. Scheduling Coordinators representing all loads and exports, including ETC and TOR schedules, would benefit from this direct refund. This revised mechanism for distributing the over-collection of marginal losses is explained below in Section 5.8.
- The current practice of exempting TOR schedules from access charges would continue.
- The current practice of exempting TOR schedules from UFE and Neutrality charges would continue.

The CAISO continues direct discussions with TOR entities to develop proposed resolutions for other issues, such as the modeling of TORs in future CRR studies.

4. Market Power Mitigation Issues

4.1 Cost Components of Default Energy Bids

In its conceptual filing the CAISO indicated that it would prefer PJM style market power mitigation, and FERC approved this request. Under the PJM-style of Market Power Mitigation generator bids that are identified as having potential market power are mitigated to what is termed “Default Energy Bids” or DEBs. These DEBs are administratively set bid curves. Market participants have a constrained choice as to how their DEB will be calculated. They must rank their choices from amongst three different methods, namely

- [A] Variable cost + 10%.
- [B] A weighted average LMP based on the lowest quartile of LMPs set at the unit location during hours in the last 90 days when the unit was dispatched. Generators must pass a competitiveness screen to qualify for this option in which 50% of their MWh dispatches over the prior 90-days must have been unmitigated
- [C] Amount negotiated with the Independent Entity.

In their February 23rd 2005 report, LECG highlighted the need to correctly identify specific costs used in calculating administrative caps that may be applied to suppliers such as the Default Energy Bid. Inaccurate identification of these costs, they pointed out, may lead to market inefficiencies or unintended incentives that could otherwise have been avoided. The CAISO whitepaper on Default Energy Bids delineated a number of issues for stakeholder feedback, the main issues of which are summarized below.

Concerning the Variable Cost Option

1. The Default Energy Bid requires a gas index price in the DA framework to be calculated. DA gas prices are not available in a sufficiently timely manner for the DA process to use the actual DA gas prices. The CAISO proposed that the calculation of the DEB be based on a proxy (Dispatch Gas Index or DGI) rather than an Actual Gas Index (AGI). As the Default Energy Bid will be eligible to set the LMP at its location, the CAISO further proposed that LMPs, once set, should not be adjusted after the fact. Both Settlement and Dispatch will thus be on the Dispatch Gas Index rather than an Actual Gas Index.
2. There are four DA gas indices that the ISO believes could be used to calculate the Dispatch Gas Index. These are Platt’s Gas Daily, Btu Daily Gas Wire, NGI’s Daily Gas Price Index, and the ICE index. The ISO indicated that for purposes of calculating the DGI it would average all four indices for each day such that the average would be a one-day average of all four indices.
3. Given the fact that the actual DA gas index cannot be used the CAISO proposed to use the most recent gas index that it has in its possession to calculate the DEBs. In the vast majority of cases this will be an index that is one day old. As the CAISO intends to have separate DEBs for DA and RT as well as for Peak and Off-Peak it is likely that the DA and RT DEBs will use different (i.e. the most recent) gas indices for calculation.
4. The CAISO proposed that DGI would include proxy figures for intra-state gas transport costs in much the same manner that current RMR reimbursements model intra-state gas transport costs. These proxy costs would be based on the PGE gas rate for units either in or closest to that gas carrier service zone and the higher of the SCE/SDGE gas rate for units in or closest to SCE/SDGE service territories.
5. The CAISO proposed that Municipal Use fees be excluded from the DEB calculation as they are seldom billed to the ISO and additionally the ISO would have to proxy them, and a readily available proxy for these fees is not available.

6. The CAISO proposed that the current emissions chargeback process for emissions be preserved, and that emissions not be modeled in the DEB.
7. The CAISO proposed that the standard default value for variable O&M for all units to be set at $2. The exception to this would be the Gas Turbines (using any fuel type) and Reciprocating Engines, which would have a default of $4. Should any market participant believe that its interests are being harmed by the default values it would be able to provide information to the Independent Entity to justify a different O&M rate.

Concerning the LMP Option

1. In the conceptual filing the ISO stated that it would only use LMPs where the resource was not dispatched up to relieve a non-competitive constraint. The reasoning was simply that the ISO wanted the LMP to reflect “competitive” LMPs, rather than LMPs reflecting potential market power. On further reflection the ISO realized that because under the PJM-like LMPM resources are automatically mitigated if they are dispatched to relieve congestion on non-competitive transmission constraints, LMPs during these periods should reflect a competitive outcome. Given this, the ISO proposed that it would be better to simply make the average an average of all LMPs regardless of whether the LMP is affected by local market power bid mitigation.
2. The purpose of the CAISO mitigation system is to prevent market participants who might potentially have market power from exercising that power and to that end the overall purpose of the MPM system is to mitigate the behavior of market participants to what would be expected under competitive conditions. Under competitive circumstances generators will bid in their marginal cost, and will receive at least that, and often more when prices clear above their marginal cost. Under the mitigation system it is important to mitigate their bids to what they would have bid rather than what they would have received. The ISO does not limit the LMP at their node and mitigated generators might well receive an LMP well in excess of their bid in most circumstances. The CAISO thus proposed that when calculating the LMP option a weighted average of the lowest quartile of the relevant LMPs be used, as this will more closely approximate the unit’s marginal cost than by having the subset include all LMPs. The relevant LMPs are simply the generator LMPs set when the generator was dispatched for energy.

Concerning the Negotiated Option

1. The third method by which a DEB might be calculated is simply entitled the “Negotiated Option”. Under this option the independent entity would use documentation supplied by the market participant and its discretion to determine the DEB, in a manner similar to what currently prevails with respect to reference levels.

Stakeholders had a number of concerns with the CAISO’s proposals.

1. Stakeholders had firm views as to which gas index should be used. The main request was that if the ISO mitigated bids in the DA market it should mitigate them to Default Energy Bids based on the DA gas index for that very day. The CAISO believes that this is just not possible given the timelines of the DAM. For the functioning of the DA market all the DEBs have to be calculated prior to 10AM. No DA gas index arrives prior to 10AM. Some stakeholders suggested use of the InterContinentalExchange index. CAISO contacted ICE and gathered information concerning its index products. Most gas trading on ICE occurs early in the morning between 6AM and 8AM, however the index is not finalized until 10AM PST, which is still too late for the DAM. This index will be included with the other indices though, and the CAISO committed to use the most recent gas index available to mitigate this risk as much as possible.
2. Stakeholders voiced concern that the real-time prices were higher than the DA indices that the ISO was using for mitigation and that some sort of adder should proxy this real-time

premium over the DA index. The CAISO indicated that it is prepared to insert elements into the DEB formula where there are cost implications that are both significant and not offset by commensurate countervailing benefits at other time periods. In this case the CAISO was unable to determine the nature of the differential between DA and RT, due to the absence of a RT index. In addition, gas prices rise and fall, hence on some occasions the RT price will be lower than the DA price and units will receive a benefit from the difference between DA and RT. If an adder were inserted to account for this “cost” differential it would, on occasion, overstate a unit’s marginal cost and result in inefficient dispatch. The CAISO believes that it would be inappropriate to model the potential difference between DA and RT gas prices simply as a cost, when in reality it is both a cost and a benefit at different times. The ISO investigated this issue, but believes that the current 10% adder being proposed for the DEB is adequate to cover any potential inaccuracies in actual gas costs, including real-time gas purchases, and does not intend to add an additional real-time premium.

3. Market Participants made the case that the DEB should include an element that reflected the increased costs they face due to the declaration of Operational Flow Order (OFO) [21] days by the gas carriers. In the normal course of events market participants will reflect the increased risk of an OFO day in their submitted bids, but if they are mitigated they indicated that they would like their mitigated bids to similarly reflect the increased risk of an OFO day. The ISO believes that OFO days are only important under two circumstances, namely when a unit is decremented via a mitigated bid on an overpressure day, and when a unit is incremented via a mitigated bid on an under pressure day. The current ISO mitigation system resolves intrazonal congestion in real-time and units are often decrementally mitigated in real-time, whilst other units are incremented. Under MRTU, all transmission constraints will be enforced in the DA framework and as a result, the CAISO has not proposed RT mitigation in the decremental direction. Under MRTU, the CAISO will only mitigate bids in the incremental direction, not the decremental direction, so the dispatch instructions of the ISO should no longer result in market participants being forced to incur OFO penalties on overpressure days due to mitigated bid dispatch. If generators are incremented or decremented in real-time for the run-of-the-mill balancing reasons it will be according to their submitted bids, which should reflect the risks of OFO imbalance penalties, subject to the Bidding Activity Rules. Regarding under pressure days the ISO recognizes that this is a concern, but does not feel that an event that is so sporadic should be modeled in the DEB. The ten percent adder is present every time a mitigated bid is dispatched and this constant adder should easily make up for such an infrequent event. For these reasons the CAISO declined to model OFO days in the DEB.

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[21] An Operational Flow Order is a condition imposed by the gas carriers on the users of the gas system. There are two types of OFO days

1. Overpressure days: these occur primarily in the summer (the injection season) when the gas pipelines are full and generating units are required to burn no less than what they have scheduled within a set tolerance band. If generators are decremented they do not use up their scheduled gas and may incur penalties if they cannot balance their schedules.
2. Underpressure days: these occur primarily in the winter (the withdrawal season), when generating units are required to burn no more than they have scheduled, again within a tolerance band.

OFO days are relatively common. Publicly available information from PGE indicates that for their system between January 2002 and the end of July 2005 (just over 3 and a half years) there were 161 OFO days called in total. Of these 14 were low inventory days (underpressure), of which 7 were customer specific and 147 were high inventory days (overpressure), of which 7 were customer specific.

This works out to an average of 3.5 underpressure days a year, of which 1.75 are for small groups of customers, and 42 overpressure days per year, of which 2 are for smaller groups of customers.

Further general information is available at
http://www.pge.com/pipeline/library/ofo_efo_diversions/ofo_index.shtml

4. Members of the generator community were uniformly opposed to revisiting the O&M adder. This issue has a long and contentious history and members believe that FERC has already ruled on this issue and that the ISO should not revisit it. Stakeholders from LSEs believe that it should be revisited. There are a number of reasons why the CAISO believes that this $6 O&M charge should be revisited.
   - The circumstances in which the original decision was made have long since ceased to exist. The $6 O&M decision was part of a broader FERC decision that put in place a mitigation system that itself is no longer operational, despite the longevity of one of its constituent parts. Far from having a mitigation system based on variable cost bidding during Stage 1 emergencies the ISO will have a PJM style mitigation approach for Local Market Power Mitigation and a bid cap for System Market Power Mitigation. The CAISO's Local Market Power Mitigation system under MRTU is far removed from the original mitigation system that implemented the $6 O&M charge and it is appropriate that it should be revisited.
   - In its $6 O&M decision FERC referenced a document, which specified that the long-term O&M costs of a steam unit were $6. FERC further reasoned that these units would be on the margin in California. The document in question is Table 3 of "Trends in Power Plant Operating Costs" by J. Alan Beamon and Thomas J. Leckey found at http://www.eia.doe.gov/oiaf/issues/power_plant.html. The CAISO contacted Alan Beamon at the EIA and he indicated that the document is dated and is not being updated any time soon. The CAISO believes that better data is now available than this study. There have also been substantial generation additions of new Combined Cycle Gas Turbines (CCGTs) to the California generating mix. Whilst it is still true that during the summer the older gas-fired units are on the margin, for much of the rest of the year this is not true, now more than ever before. The CAISO does not believe that the O&M characteristics of a minority of units should be used to determine the O&M values for all units.
   - Whilst the ISO believes that the methodology FERC used to establish the O&M rate for its Stage 1 based mitigation measures was appropriate for the circumstances, namely the tail end of the energy crisis, constrained by the need for haste. The ISO does not believe that this methodology is appropriate now. Setting the O&M rate for all units for all hours of the year based on the O&M of the marginal unit on the peak day of the year is a blunt and imprecise methodology in today's more rational markets. Using such a methodology will result in the DEB not resembling the actual variable O&M costs for all but the very oldest steam units. It is as if the variable cost for the system marginal unit on the peak day were imposed year-round for all units for all days as an approximation of variable cost. The CAISO believes that a better methodology can be found and that unlike the crisis conditions that called for a rapid mitigation response using a generic O&M value for all units, there is now, under the MRTU design effort, ample time for units to provide unit specific variable O&M values prior to the start of MRTU.
   - The CAISO is revisiting much smaller issues than the $6 O&M charge. The gas transport costs mentioned earlier in this document will most likely be less than $0.40c/MWh. It would make no sense to leave the $6 O&M charge untouched whilst going into such detail about far lesser charges.
   - The ISO's enquiries into the methods used by other ISOs reveals that were the $6 O&M to continue, the CAISO would be held to a different standard than other eastern ISOs. MISO, for example, requires Market Participants to submit their variable O&M costs.
5. Stakeholders had a further concern with the LMP option where the CAISO's proposal shifted the subset of LMPs from all LMPs set when the generator was dispatched to the lowest

quartile of LMPs set when the generator was dispatched. Stakeholders had reservations concerning this proposal; in particular the opinion expressed was that it was a substantive deviation from the conceptual filing. The CAISO believes that though the final formulation is different to the conceptual filing this is the only method of implementation which will allow for the LMP option to conform to the overall purpose of mitigation, and that the change is within the boundaries of the conceptual filing.

4.2 Bid Adder for Frequently Mitigated Units

Units that are frequently mitigated (Frequently Mitigated Units, FMU) will be eligible to have a Bid Adder added to their Default Energy Bid (DEB). The issues that were resolved included how a unit will be designated as an FMU, what the dollar-value will be for the per MWh default Bid Adder, and how units with a portion of their capacity under RA contract will be treated within the FMU framework.

The general criteria for determining whether a unit is Frequently Mitigated and eligible to have the FMU Bid Adder applied to its Default Energy Bid will be established on a monthly basis.

A unit will be designated as an FMU if the following conditions are met:

- Unit is mitigated in over 80% of its run hours over a rolling 12-month period.
    - Any hour in which a unit has positive metered output will count as a run hour.
    - Any hour in which a unit had a mitigated bid segment dispatched will count as a mitigated hour.
- Unit ran for more than 200 hours over the rolling 12-month period.
- Unit does not have a capacity contract with the CAISO and is not fully contracted with an LSE to meet RAR.

The CAISO proposal limits application of the Bid Adder to the cost-based DEB option. If a unit owner is eligible for a Bid Adder but has elected the LMP based DEB option, they would have the choice of having a new DEB based on the cost-based option plus the adder or keeping the LMP based option.

For the first 12 months of MRTU, the CAISO will use data on RMR dispatches and incremental Out-of-Sequence dispatches as surrogate, or proxy, measures of when a unit would have had their bids mitigated by the LMPM under MRTU when calculating mitigation frequency for comparison to the 80% threshold stated in the criteria above. The CAISO will use MRTU data in the 12-month rolling period as this data becomes available. For new units that come online within twelve months of the start of MRTU, the evaluation of eligibility criteria will be based on data available since the first date the unit became available to put energy onto the grid. In this regard, the 200 run hour restriction will be pro-rated to the proportion of the 12-month period that the new unit has been online.

Once the CAISO determines that a unit is eligible for the Bid Adder, that unit will have added to its cost-based Default Energy Bid either the default Bid Adder value or a unit-specific Bid Adder value arrived at through consultation.

The CAISO has proposed to use the same formula to calculate the default Bid Adder value as is used in PJM, where the per MWh dollar value is calculated as the ratio of Annual Avoidable Fixed Cost / Annual Expected Energy Production. Current data on avoidable costs for existing CTs was insufficient and so the CAISO is proposing to use the calculated Bid Adder value resulting from using the Fixed O&M cost figures for a new CT in California that are reported Appendix D of the California Energy Commission 2003 Final Staff Report titled "Comparative Cost of California Central Station Electricity Generation Technologies". These figures result in a calculated default Bid Adder value of $24/MWh. Note that this is a default value and that unit owners have the option to present cost data reflecting their unit specific avoidable costs to the

CAISO or otherwise designated Independent Entity to receive a consultative Bid Adder value that is specific to that single unit.

Units with some portion of their capacity under an RA contract will not be prohibited from receiving a Bid Adder. If a partial-RA unit meets the eligibility criteria to receive a Bid Adder, the Bid Adder (default or consultative) will be pro-rated to reflect the proportion of that unit's capacity that is not contracted. For example, an FMU with 75% of its capacity under an RA contract would receive a $6/MWh Bid Adder as the default. The pro-rated Bid Adder for partial-RA units will be applied to the entire cost-based DEB.

The following are some of the primary Stakeholder comments on this issue along with the CAISO response.

- The mitigation threshold at 80% of run hours is too high and a lower threshold should be considered.

  CAISO response: The 80% mitigation threshold for designation as Frequently Mitigated, and for Bid Adder eligibility, is an established threshold approved by FERC and implemented in the PJM revenue adequacy mechanism for Frequently Mitigated Units. Units that are not mitigated in over 20% of their run hours should have sufficient opportunity to recover fixed costs through infra-marginal rents occurring at their location during their unmitigated run hours. However, such units have the option of seeking a negotiated Default Energy Bid that could include a contribution to going forward fixed costs if they can demonstrate that they cannot adequately recover sufficient revenues from the market and the CAISO determines they are critical to meeting local reliability needs.

- Basing the Bid Adder on avoidable costs does not adequately cover all fixed costs incurred and consequently does not provide sufficient revenue adequacy to FMUs.

  CAISO response: The Bid Adder is a short run mechanism intended to provide sufficient revenue to cover the incremental costs incurred by units that decide to continue running rather than shut down. The Default Energy Bid insures variable cost recovery, and the Bid Adder is structured in a way that covers any fixed costs that would "avoidable" should the unit owner choose to shut down. This mechanism is short-run in nature in that it is not intended to insure recovery of all fixed costs for an indeterminate time period. In the medium-run, units that are frequently mitigated and require a Bid Adder may be determined to be needed for reliability. In this case, either an RA contract or a contract with the CAISO would be extended to cover the costs of maintaining the unit in the medium-run. In cases where such a unit is not needed for reliability, it may be uneconomic for that unit to be in operation and that unit owner may choose to retire the unit.

- It is unlikely that a unit would be able to recover all of their fixed costs from an RA contract that covered only a portion of the unit's capacity.

  CAISO response: Through interaction with Stakeholders, the CAISO has come to agree that the Revenue Adequacy mechanism for FMUs should accommodate units that are partially contracted under the Resource Adequacy framework. The instant proposal includes provisions that allow a partial-RA unit that meets the other eligibility criteria to receive a Bid Adder scaled in proportion to the percent of unit capacity that is not contracted.

4.3 Competitive Path Assessment

The classification of transmission paths as "competitive" or "uncompetitive" will have a material impact on the amount of bids that will be mitigated for local market power. The broader issue that has been resolved is the specific methodology and test criteria that the CAISO will use to determine whether a transmission path is deemed "competitive" in the application of the Local Market Power Mitigation. There are several specific sub-issues that have been resolved that include:

- The methodology used to determine whether a supplier is pivotal in relieving congestion on a particular transmission path,
- The sets of paths that will be tested for competitiveness and the sets of paths that will initially be considered competitive and not tested,
- Treatment of imports,
- Treatment of fixed-priced contracts,
- The competitive test thresholds.

The salient features of CAISO proposal are as follows:

Methodology for Measuring Competitiveness: The CAISO has resolved to adopt the Feasibility Index (FI) method as the core methodology. The basic idea underlying the methodology proposed here is to take out all supply resources of a specific supplier (or more suppliers if two or more jointly pivotal supplier analysis is desired) and determine if the remaining suppliers' resources can be scheduled to meet the load subject to the transmission constraints, i.e., if a feasible solution exists with the remaining supply. This is done simultaneously for the entire system's set of loads, resources, and transmission facilities. In case a feasible solution does exist, the supplier(s) in question are not pivotal for congestion relief on any path under the set of supply/demand/system conditions. Otherwise the supplier(s) in question are pivotal for congestion relief on the paths that cause solution infeasibility. To identify those paths and quantify the relative degree of infeasibility each cause, we define a feasibility index (FI) for each transmission constraint with respect to each supplier. To define the FI index, we modify the basic scheduling and market clearing by treating all transmission constraints as soft constraints with very high penalties (orders of magnitude higher than the highest bid price or the prevailing bid cap) for violating the constraint. Thus, instead of getting no solution, we would get a least cost solution in which some transmission flows exceed the transmission (constraint) limit.

Path Selection: ISO proposes to use a list of candidate competitive paths based on historical annual congestion frequency (500 hours or more per year). Also, the ISO proposes a retained (grandfathered) list of competitive paths (namely, the existing inter-zonal paths) for the first FI study such that the FI method cannot designate them as non-competitive. In parallel, the ISO will conduct FI studies both with no candidate list (all paths potentially competitive) and no grandfathered list (all paths potentially non-competitive) to assess the viability of these alternative options for application in the subsequent annual assessments.

Treatment of Imports: CAISO proposes not to treat the imports as pivotal suppliers, but to use their historical levels, and where relevant historical bids (price-quantity) as the study input data.

Treatment of Fixed-Priced Contracts: CAISO proposes to consider, to the extent possible, two types of contracts that are reported to FERC when generators file applications for triennial renewals for market based rate authority (MBRA). These contracts include those which involve (1) multiple owners of generation units, and (2) granting a second firm operational control of a unit. These contracts impact only the supply concentration for pivotal analysis.

Competitive Test Thresholds: The FI methodology allows for testing of whether or not a supplier or set of suppliers is pivotal. The CAISO has adopted a no-three-pivotal supplier test where if any three or fewer suppliers are deemed pivotal using the FI method with respect to a particular path, then that path will be considered "not competitive" in the application of LMPM.

The main stakeholder comments and CAISO responses are summarized below:

Comment: The no-three-jointly-pivotal supplier test is too conservative:

CAISO Response: Our proposed three-pivotal supplier test is less stringent than PJM's since we include all suppliers, whereas PJM considers only a fraction of the suppliers (the first quartile of supply on the effective price-quantity curve) as the pool of suppliers to which the three-pivotal supplier test is applied. Nevertheless, if we can work out a means of incorporating price movement impacts in our proposed methodology, as we have stated we would consider moving to two-pivotal supplier test.

Comment: Bilateral contracts should be considered in the analysis:

CAISO Response - Partial unit ownership seems rather straightforward to take into account. However, to the extent that a single entity (perhaps one of the owners or the SC of the unit on behalf of all owners) may be the entity that decides on the bid price and quantity for the whole unit, one should incorporate the whole unit in the portfolio of that entity. The same consideration applies regarding delegation of operational control to another entity (if we discount the owner's portfolio, we should augment another entity's portfolio that has been delegated operational control of the unit). CAISO will make a best effort to incorporate these types of contracts in pivotal supplier analysis.

Comment: Competition to relieve congestion on a path may be seasonal:

CAISO Response - The going forward designation is a common practice. No ISO is currently performing a forward temporal (seasonal) designation. We will start the MRTU market based on such designation, and while gaining experience with the LMPM under the LMP paradigm in California; we will investigate the pros and cons of seasonal designation (with and without repeating the analysis every season) for possible implementation for year 2 of MRTU operation.

Comment: Competitive status of a path should be conditioned on load level:

CAISO Response - The designation of a path as competitive is made for all credible combinations of system and load conditions. If the load on a given day is below the load level used for such designation, there is no need to change the designation. If the load level is low enough not to require the pivotal supplier to meet the load in the load pocket bounded by the designated non-competitive paths, then all load in the load pocket can be served. So, whether or not the constraints into the load pocket are designated as competitive (included in Pass1) or not (included only in Pass 2) the pre-IFM mitigation outcome would be the same.

Comment: Path assessment should consider all internal supply resources:

CAISO Response - All resources will be included. Intermittent resources will be included based on historical output levels commensurate with system and load conditions used in the scenario.

5. Spot Market Issues

5.1 RUC Self-Provision

During the technical conferences organized by FERC in the first half of 2004 some parties asked the CAISO to provide a mechanism whereby market participants who would be exposed to charges for CAISO RUC procurement could self-provide RUC capacity, thereby reducing the amount of RUC capacity to be procured by the CAISO and avoiding a commensurate share of the RUC procurement charges. The CAISO subsequently developed a proposal for RUC self provision, presented it to stakeholders in the course of the 2005 stakeholder process and on several occasions in meetings and in white papers requested comments. Although a few parties stated that RUC self provision should be retained in the MRTU design, more parties suggested that it be dropped, and no party commented specifically on the CAISO's proposal. The issue at hand is whether the CAISO should retain this feature in the MRTU design.

The CAISO now proposes to drop RUC self provision from the MRTU design.

As noted above, the CAISO has repeatedly asked stakeholders to comment on whether the RUC self provision feature should be retained, the specific needs this feature addresses, and whether the CAISO's specific proposal for RUC self provision meets such needs. Over the past several months only two parties have indicated that RUC self provision should be retained, but did not comment on the CAISO's proposal. One party – State Water Project – described its specific concerns that a RUC self-provision feature might address, but did not comment on whether the CAISO's RUC self provision proposal would address their concerns. Several other parties commented that RUC self provision should be dropped from MRTU.

5.2 Pricing Ancillary Services Procured in Hour Ahead and Real Time

Under the MRTU design the CAISO will procure 100 percent of its anticipated Ancillary Services requirements in the Day Ahead Integrated Forward Market (IFM). Nevertheless in many cases the CAISO will need to procure additional A/S in the HASP or the Real Time market, due to changes in system conditions such as plant outages or transmission derates, or to real-time demand exceeding the day-ahead forecast. The issue is how to structure the price the CAISO will pay for A/S procured in the HASP or Real Time market.

The CAISO proposes the following:

- The CAISO will procure A/S in RT from internal generation on a 15-minute basis, and will pay a 15-minute MCP based on the A/S capacity bids submitted to the Real Time Market and the opportunity cost of resources skipped in the merit order dispatch to provide reserves.
- The CAISO will procure A/S from imports in the HASP on a 60-minute basis, and will pay a MCP based on both energy opportunity cost and A/S capacity bids. Import capacity procured, as A/S in HASP could be responsible for congestion charges if the capacity is scheduled on a congested intertie.

There were no opposing stakeholder comments on CAISO's proposal.

5.3 Pricing and Cost Allocation of Intertie Schedules Determined in HASP

In initial MRTU design (as well as in initial implementation of Phase 1b), the hourly bids (imports and exports) were guaranteed bid or better, receiving (or paying) real-time price established by 5-minute dispatchable resources plus an uplift (a reimbursement) when needed to make them whole for their dispatched bid. Serious concerns were raised regarding strategic behavior as well as cost shifts associated with this pricing and settlement scheme after the implementation of Phase 1b. An interim solution ("as bid" settlement of tie bids) was adopted in Phase 1b. Meanwhile, in their review of the initial MRTU design, LECG pointed to NYISO's experience with hourly import bidding and settlement, and recommended a change in ISO's initial HASP design whereby the imports would be settled based on pre-dispatch hourly prices when (and only when) there was congestion on the tie[22]. In it's May 31, 2005 MRTU filing, the CAISO stated that the issue of inter-tie pricing and settlement in HASP would be addressed in the MRTU stakeholder process.

To remedy the problem in MRTU, CAISO proposes a 2-pronged solution in order to:

(a) Align the pricing (bid or better) and payment to the hourly pre-dispatched bids with their dispatch.

(b) Align cost allocation associated with these payments based on cost causation.

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[22] In their review of the HASP design, LECG did not realize that the "bid or better" provision in the initial design applied to both the imports and the exports. Their recommended solution would thus have the same drawbacks as the initial design in the absence of tie congestion.

The two parts of the solution are explained below in section 5.3.1 and 5.3.2 respectively.

Proposal for HASP Intertie Pricing

CAISO proposes to use an hourly pre-dispatch price (LMP) for settling both incremental and decremental energy (imports and exports) at the relevant interties with daily bid cost recovery guarantee. The hourly pre-dispatch price will be a simple average of 15-minute predispatch prices for the next operating hour.

Note: Real time hourly bids are pre-dispatched based on their inc/dec bids 45 minutes prior to the next operating hour, based on forecast of system imbalance energy needs with 15-minute resolution. CAISO uses a 15-minute load forecast for this purpose because it runs a 15-minute unit commitment to procure ancillary service shortfall in real time. CAISO calculates separate pre-dispatch prices for each 15-minute interval of the next operating hour; all four quarter-hour prices are computed at the same time (T-45) for purposes of establishing the hourly pre-dispatch price. Both the import bids and internal supply bids are used to meet the load forecast and export bids. Inter-tie bids that are pre-dispatched during HASP run as well as internal resources will be eligible to set the LMP. If there is congestion on an inter-tie interface (branch group) the price of the inter-tie will reflect the congestion.

Developing market-clearing prices to settle with incremental and decremental energy at interties is superior to the current (Phase 1b) pay as bid scheme since it would encourage suppliers to bid in their marginal costs. This was in fact the preferred approach to resolve the post Phase 1b implementation inter-tie pre-dispatch settlement issue, but it was not adopted due to implementation constraints.

Although the 4 quarter-hour predispatch prices at a tie for an operating hour could be different, since they are computed simultaneously (at T-45), it can be shown mathematically that (under a set of assumptions that are generally expected to be valid) their simple average is equal to or higher than the highest accepted hourly import bid and equal to or less than the lowest accepted hourly export bid. The additional provision for bid cost guarantee is just to address any doubts or concerns about the validity of such mathematical properties under extreme situations. Although this bid cost recovery provision will likely never be invoked, its inclusion does not involve additional software effort (bid cost recovery uplift over 24 hours is already a feature in MRTU software Release 1 for other reasons).

BPA Comment: “Import predispatch sellers would never receive a price set within the CAISO control area. The intertie “LMP” could be expected to be generally lower than the price within the CAISO control area, as import predispatch bidders would often be bidding against one another to market near-term surplus energy”.

CAISO response: As explained above, real time bids of internal resources will be considered in determining the Predispatch market-clearing price. As an example, let’s assume that the highest import bid at an intertie (ex: Palo Verde) is $30. Assuming there is no congestion and the predispatch requirements exceed interties bids, CAISO will consider the bids of internal resources in the predispatch process to meet the 15-minute load forecast plus export bids. The Predispatch price could be set by a SP15 resource at $40 if it is the marginal unit. Therefore, the setting of predispatch clearing price is not limited to only the interties bid prices.

Note: The CAISO does not expect any systematic bias between pre-dispatch and real-time prices. So, the basis for the assertion made above, namely, “the intertie LMP could be expected to be generally lower than the price within the CAISO control area” in unclear to us. In fact, the concern expressed by the internal suppliers is exactly the opposite, namely, higher pre-dispatch prices than real-time prices. Neither assertion for a systematic bias has a defensible basis that the CAISO is aware of.

BPA Comment: "A local price at the ties for clearing the predispatch market should only be set when there is congestion. The LECG proposal is superior in that LMP at the interties is limited to times when there is congestion, but it is not clear where the price would come from when there was no congestion. Would intertie predispatches absent intertie congestion be paid the real-time MCP under the LECG option?"

CAISO response: LECG's recommendation was based on the practice in NYISO, where imports are guaranteed bid or better but exports are not. So, under their recommendation absent intertie congestion imports would be paid the higher of the real-time price or their bid, but the exports would have no guarantee of being charged no more than their bid price. In fact, under LECG's recommendation exports would subsidize the payment to the imports whenever the real-time price is higher than the pre-dispatch price.

BPA Comment: "ISO should allocate the lowest priced predispatch schedules to system needs. ISO states that allocation of predispatch schedules between system requirements and market clearing is arbitrary. It is not arbitrary, nor is it ambiguous, and thus it is not dispute-prone."

CAISO response: It is unclear to us how the proposed allocation scheme could be implemented without developing an exhaustive set of rules for each conceivable special case that all market participants could agree to. Let's consider an example.

PD Import = 120 MWh from two suppliers:

- Supplier A: 20 MWh bid segment at $30 and 40 MWh bid segment at $40
- Supplier B: 40 MWh bid segment at $30 and 20 MWh bid segment at $40

PD Export = 100 MWh at $55

PD Price = $50/MWh

RT Price = $30/MWh

Settle 100 MW of import/export clearing at PD price:

Import is paid: 100 ($50) = $5000 and Export is charged $5000.

For the net 20 MW import (used for system imbalance), according to the approach proposed the cheapest segments of import bids are assigned to RT and more expensive segments to PD. Thus 20 MW of the $30 bids are paid the RT price of $30: 20 MW * ($30) = $600. The question is whether these 20 MWhs are coming from supplier A, supplier B, both suppliers pro rata based on their bid segments at or below $30, or some other criteria. The situation becomes more complex and ambiguous if the ties where suppliers A and B submit their bids are different, and there is real-time congestion on the internal paths giving rise to different real-time prices for the two suppliers.

Powerex Comment: supports CAISO's proposal for intertie predispatch pricing.

CAISO response: Support is gratefully acknowledged.

Calpine Comment: The ISO proposal discriminates against internal generation. HASP should consider internal resources for unit commitment in 1-hour increments and should financially settle imports and internal resources in a consistent manner for offering similar products.

CAISO response: As stated in the white paper, expanding the provision for hourly bidding to internal generation resources will be addressed as part of Release 2 MRTU stakeholder discussions. In its design and implementation of an hourly pre-dispatch market for internal resources the CAISO must strike a balance between the flexibility for the internal resources to participate in the pre-dispatch bidding and settlement, the dispatch flexibility needed for reliable real-time operation, consistency and incentive compatibility among the hourly, 15 minute, and 5 minute real-time markets in all of which the internal resources can participate. The CAISO is unable to achieve this goal in Release 1.

Proposal for Predispatch Cost Allocation

The difference between the payment to the suppliers (based on pre-dispatch LMPs for net imports and real-time LMPs for net incremental dispatches of internal generation) and charges to NNUD[23] (based on the LAP price for underscheduled load and nodal LMP for supply uninstructed deviations) is referred to as Neutrality imbalance (N) [24]. Because a basic CAISO principle for allocating costs to Market Participants is to follow cost causation to the extent possible, in an earlier proposal the CAISO had suggested allocating N partly to NNUD and partly to Metered Demand. Subsequent analyses revealed, however, that any such partition would be arbitrary due to the absence of clear cost causation linkages between any predispatch uplift and NNUD. To avoid creating a cost allocation mechanism that is needlessly complicated and ultimately arbitrary, the CAISO now proposes to allocate N to Metered Demand.

WPTF Comment: CAISO should use separate charge types to distinguish cost allocation from other imbalance energy allocations such as UFE.

CAISO response: As noted above, such a distinction in this case would be arbitrary.
Powerex Comment: CAISO should maintain a full hour ahead market and allocate the predispatch costs to deviations between day ahead and hour ahead markets.

CAISO response: This will be included as part of the Release 2 discussions.

5.4 Definition of Trading Hubs

This topic has been addressed on a parallel track with the other MRTU issues, in conjunction with the FERC settlement proceeding on Seller's Choice contracts. The proposal developed by CAISO staff in conjunction with stakeholders was approved by the Board on January 27, 2005, and was filed on March 15. In an order issued on June 10 FERC approved this filing. In addition to providing a detailed design proposal for Inter-SC Trades for bilateral energy transactions, the filing also included a proposal for Existing Zone Generation Trading Hubs ("EZ Gen Hubs"). The EZ Gen Hub proposal was the result of an extensive stakeholder process on the issue of trading hubs under LMP, which culminated in general stakeholder agreement that the CAISO should develop EZ Gen Hubs as successor delivery points under LMP for today's existing internal congestion zones (NP15, SP15, and ZP26). Furthermore, there was general stakeholder agreement on a basic definition of EZ Generation Hubs, in that they would be formulated to represent the average price paid to generation within the zone and as such, would be based only on LMPs at generation nodes. Several different options were discussed with stakeholders on how EZ Gen Hubs would be calculated in terms of whether the EZ Gen Hubs would be comprised of all generation nodes within the zone or a representative subset and whether the weighting factors for each node would be fixed or dynamic. However, there was no final resolution on these technical details. Upon review of tariff language defining trading hubs for other ISOs and RTOs, the CAISO concluded that the details of the CAISO's EZ Generation Hubs were sufficiently developed for purposes of preparing tariff language.

Concerning the November tariff filing the CAISO proposes that the language reflect the fact that the trading hub prices would represent the average price paid to generation in the zone.

The CAISO then proposes to resolve the technical details subsequent to the tariff filing, based on analytical work that will proceed along two paths. Along the first path, the ISO will model and

[23] Net Negative Uninstructed Deviation (NNUD) refers to underscheduled load and overscheduled generation.

[24] N could be a surplus due to real time supply and demand deviations. Allocating revenues to uninstructed deviations does not send the proper signal for scheduling accurately. The proposed cost allocation, in this case, is not purely based on cost causation.

analyze the different potential formulations of the trading hubs. There are a number of reasons for doing this.

- It is important that whatever formulation of the trading hubs emerges is not significantly different from the "average price paid to generation in the zone," which is the fundamental definition agreed to in an extensive stakeholder process last year and was filed and approved by FERC in its June 10, 2005 Order.
- The final formulation needs to be robust and predictable and modeling the results will give an indication of that.

The modeling of the formulations will involve analysis of the LMP results from previous CAISO LMP studies (3A and 3B), as well as potentially some production-cost modeling. When this analysis is completed the ISO will present the results to stakeholders and will offer the CAISO's own proposal for resolution of this matter.

The second path builds upon the effort of a subset of the stakeholder group that has formulated a position that represents a consensus amongst those involved in the discussions. There is currently a further effort underway to attempt to broaden the appeal of that formulation. Whatever the result of this process the CAISO will still perform the modeling work and present its own proposal, but obviously if the smaller stakeholder proposal gains significant traction among a broader stakeholder base the CAISO will be pleased to model and analyze that formulation as well as those currently under consideration.

The CAISO believes that the analyses described above are necessary and prudent steps for determining the best approach for implementing the EZ Gen Hubs. These analyses cannot be completed and discussed with stakeholders in time to reach a resolution to incorporate in the CAISO's November 2005 filing of the MRTU Tariff.

Stakeholders had some concerns with the Trading Hub Proposal, namely

- Most stakeholders would prefer that the tariff language more clearly define the trading hub definitions, such that it specifies the nature of the average (simple, weighted, subset etc.) and the nature of the weighting if any (annual, or dynamic). Some market participants would even have liked the names of the nodes to be specified in the tariff. The CAISO's review of tariff language for the eastern ISOs revealed that, although their hub definitions vary, the CAISO's formulation is in the middle ground concerning its level of detail, and certainly no other ISO has specified the actual nodes in its tariff. The CAISO agrees, however, that upon finalizing the definition of trading hubs to be used under MRTU it will reconsider with stakeholders whether the definition or certain features of it should be included in the tariff.
- Concerning the timeline to resolve these technical issues participants indicated that the tariff filing was not the sole driver behind their desire for trading hub certainty. Market participants wish to trade bilaterally beyond February 2007, and consequently they need certainty concerning the technical details to facilitate bilateral contracting. Consequently the ISO has committed to resolve the technical details in a timely fashion but separate from the MRTU tariff filing effort, and this work is ongoing. As stated earlier, the CAISO does not believe it would be prudent to settle on an approach for implementing the EZ Gen Hubs without conducting the analytical steps described above and discussing the results with stakeholders, which cannot be completed in time to incorporate in the MRTU tariff in November 2005.

5.5 Inter-SC Trades of Ancillary Services

The CAISO's current (pre-MRTU) design functionality allows for the trade in Ancillary Services by Scheduling Coordinators. The process is simple in that two Scheduling Coordinators each submit a trade for an individual service. The trades are validated and the Purchasing SC (PSC) then has an increased amount of A/S to set against its A/S obligation. In turn the Selling SC (SSC) has a reduced amount of A/S (or increased amount of A/S obligation). Market participants use this service and they have indicated that they would like a similar functionality under MRTU.

- Treatment of Imports: Under the Current Design Under the current (pre-MRTU) market, when an LSE imports firm power from a neighboring control area the A/S that is attached to the import is set against the LSEs Load Obligation. When a no-load SC imports firm energy it can also sell the attached A/S as well as the energy onto another SC or another LSE. This is done via an inter-SC trade of A/S. On the Settlements side of the process this is not an automatic function, however Settlements has a manual workaround that occurs after the fact. The intention is that under the new SaMC system this will be an automated function. The important point is that since August 1st 2002 A/S has not been stripped from imports when an SC (as opposed to an LSE) imports power for later sale to an LSE. Both SCs and LSEs remain in possession of the A/S attached to their import, albeit in slightly different forms.
- Differential Treatment Between LSEs and other No-Load Importers: Under the ISO's current design when an LSE imports firm power from a neighboring control area the A/S that is attached to the import is set against the LSEs own Load Obligation. When an SC (without any load) imports firm power it is credited with 7% reserves IF the SC sells the A/S onto someone else and performs an inter-SC trade of A/S. Once the A/S reaches load it is set against that LSEs procurement (not its obligation), as what is being traded is a Fixed Quantity rather than a Load Obligation. The difference between these two treatments is minor. What is important is the necessity to trade the A/S to recognize it. If the no-load importing SC only sells the energy and fails to sell the A/S it receives no credit of any kind, i.e. the load obligation cannot be negative, and the SC is left in the same position as a generator that failed to sell an A/S product that it had.

When the ISO first presented this issue to stakeholders in mid-August it proposed three improvements to the A/S trading methodology under MRTU. These were

1. Move from trading Fixed Quantities to trading Load Obligations.
2. Do not strip imports of their A/S when imported by a no-load SC
3. Allow negative load obligation

The majority of the stakeholders objected to element 1. Moreover, it subsequently emerged that while the automated system existing today did strip imports of their A/S a manual workaround corrected for this. In the light of the new information and based on stakeholder comments, the ISO is modifying the first element of its previous proposal.

ISO's new proposal is as follows:

1. The trade of A/S will be trades of Fixed Quantities (as it is now). The ISO is no longer proposing that Load Obligations be traded rather than Fixed Quantities.
2. Imports will not be stripped of their A/S. MRTU will automate the existing manual workaround.
3. Credit for A/S associated with imports does not require than the SC have non-negative load obligation. A SC that imports firm energy, but does not use the associated A/S to serve its own load obligation (if any), nor trades the associated A/S to someone else, will receive a financial credit equal to the relevant A/S user rate.

There was no stakeholder support for ISO's initial proposal to drop Fixed Quantities of A/S Trades in return for Load Obligation Trades. In fact, there was resistance from the generators. Participants that opposed this concept in written comments include Calpine, NCPA and SCE amongst others. As this aspect had so little traction with anyone the ISO is no longer proposing this change. Stakeholders had no problem with ISO supporting both trades of Fixed Quantities of A/S and trade of Load Obligation, however that is not a feature ISO can include in Release 1. The ISO will include this in the list of candidate features for Release 2.

The negative obligation was well supported by importers, but opposed by LSEs. It was supported in written comments by Powerex, and opposed orally and in writing by SCE. CERS also voiced concerns orally.

The ISO believes that there are a number of good reasons for this proposal, namely:

Cost Causation

Imported power reduces the CAISO's procurement of reserves. At the moment importers without load who import power but do not sell the A/S onto a LSE receive no benefit even though the ISO's procurement of reserves is reduced. Importers can only realize that benefit by selling both the energy and the A/S to an LSE. Under MRTU the no-load importer will have the choice of not selling the A/S (i.e. holding onto the A/S and incurring a negative load obligation) and being paid out at the user rate, or selling the reserves onto the LSE along with the energy. This is consistent with cost causation in that the party that creates the benefit for the ISO receives the payment.

Equal Treatment of Similarly Situated Resources

The reduction in reserve procurement that results from an import occurs in a similar manner to over-self provision by a LSE. The ISO always accepts self-provided A/S, but if the LSE over self-provides then the LSE is paid out at the user rate for that over-provision. This is conceptually similar to the negative load obligation the ISO is proposing. The proposed payout to importers for their negative load obligation at the user rate is similar to the current longstanding payout to internal generators who reduce the CAISO's procurement by over self-providing.

Day Ahead Market Efficiencies

The ISO currently does not have a Day-Ahead Market, but will have one under MRTU. In the DA IFM most generators that bid in will be bidding in energy unbacked by reserves, but firm imports will be bidding in energy backed by reserves. These are different products competing in the same market, and to treat similarly situated resources in the same way the ISO feels it should compensate imports for the A/S reduction they bring to the table. The negative load obligation will do this and will ensure that suppliers bidding into the DAM are doing so on an equal footing.

The ISO believes that its overall proposal is congruent with market efficiency, cost causation and the equal treatment of similarly situated resources. However, since the CAISO targets 100 percent of its AS procurement in the DA IFM, the CAISO may limit the negative AS obligation credits to firm imports scheduled in Day Ahead (that are also actually scheduled in Real Time).

5.6 PIRP-MRTU Integration

The CAISO implemented the Participating Intermittent Resource Program (PIRP) in 2004 to support the state’s goals for increasing wind generation and to mitigate, to the greatest extent possible, the financial risk of deviations between scheduled and actual energy from intermittent resources.

In the context of MRTU, intermittent resources are expected to comprise a portion of the capacity procured by load-serving entities (LSEs) in fulfillment of their Resource Adequacy Requirements (RAR). As part of the RAR the CPUC is expected to establish an obligation on LSEs to require their RA capacity to comply with the CAISO’s Resource Adequacy-based Must Offer Obligation (RA-MOO, described earlier in this document) and make their RA resources available to the CAISO for those periods in which they count towards meeting a LSEs RAR. PIRP resources would not be required to offer their capacity to LSEs as RA capacity, but any PIRP capacity that was procured under the RAR would have to comply with the RA-MOO. The issue, then, is to specify how the RA-MOO would apply to PIRP resources. Because the PIRP was originally designed to accommodate the specific properties of intermittent resources in the CAISO markets, the CAISO's proposed RA-MOO provisions start from the presumption that any intermittent resources procured by LSEs to meet their RAR must also participate in the PIRP as a condition for qualifying as RA capacity. Intermittent Resources that are not in the PIRP will not be eligible to be RA capacity, but may participate in the CAISO markets on the same basis as all other PGA resources.

The initial CAISO proposal for RA-MOO compliance was to impose a day-ahead must offer obligation on RA-PIRP resources, which would require these resources to schedule in the Day Ahead Market (DAM). Several PIRP participants expressed concern that this would impose undesirable financial risk on the RA-PIRP resources due to the volatility of deviations between their day-ahead forecasts and their actual real-time output. In response to the comments received and discussions held with some of the PIRP resource owners and the CPUC, the CAISO now proposes to drop the day-ahead scheduling requirement for RA-PIRP resources.

Although a RA-PIRP resource will not be required to schedule day-ahead, it will be permitted to self-schedule or bid into the DAM if the resource operator or the LSE for which the resource is providing RA capacity chooses to do so. In this case, the CAISO will discount the quantity of the RA-PIRP resource's day-ahead schedule for purposes of calculating the RUC procurement, due to the volatility noted above between the day-ahead forecasts and the actual real-time output of intermittent resources. The size of the discounting factor will be addressed early in 2006 when the CAISO takes up the task of specifying the algorithm for calculating the RUC procurement target.

Whether or not a RA-PIRP resource schedules in the day-ahead market, it will be required to self-schedule in the Hour Ahead Scheduling Process (HASP) in accordance with its forecast provided by the independent Forecast Service Provider (FSP). By complying with this HASP scheduling requirement the PIRP resource receives all the benefits that exist today under the PIRP. Due to the fact that the intermittent resources are not dispatchable they cannot provide A/S or real-time energy. This restriction simply continues rules in place today under the PIRP.

The FSP will continue to provide a day-ahead forecast no later than 5:30 am PPT on the date prior to the forecast date. If it is known that a unit will be out of service for some time or that the production of a unit will be reduced, the resource is required to provide this information to the CAISO so that the PIRP software application can transmit this information to the FSP, who takes it into account when producing the forecast.

Settlements of the HASP schedules of PIRP resources will be based on Real-Time prices. In addition, PIRP resources that provide RA capacity will be considered in the CAISO's day-ahead RUC procurement target to avoid the over-commitment of capacity in RUC. Consistent with the treatment of other RA capacity in RUC, there will be no RUC availability payment to RA-PIRP resources or any other settlement impacts on RA-PIRP as a result of this RUC calculation by the CAISO.

The PIRP will continue to accept eligible resources for a one-year commitment period, upon passing the 60-day trial period. To remain in the program, a unit must always self-schedule in the HASP according to the forecast provided by the FSP.

The CAISO's revised proposal described above is based on the discussions with stakeholders and their submitted comments.

5.7 Granularity of Load Aggregation Points for Spot Market Scheduling and Settlement

The CAISO's July 2003 comprehensive MRTU market design filing proposed that loads will be scheduled and settled using aggregations of individual network nodes called Load Aggregation Points or LAPs. The July 2003 filing provided for three LAPs corresponding to the transmission service territories of the three IOUs (PG&E, SCE, and SDG&E), and explicitly required that all loads within these LAPs (with a few narrow exceptions[25]) would be subject to load aggregation with no opportunity to opt out. Since that time some entities have raised issues and concerns with the coarseness of the LAPs, and have indicated the desire to move to more granular LAPs. In its September 19, 2005 Order FERC encouraged the CAISO and the stakeholders to work towards more granular LAPs. The following questions are relevant to this issue:

1. Should the CAISO retain the existing three large LAPs or move to more granular LAPs for spot market scheduling and settlement in the initial MRTU implementation?
2. If more granular LAPs are adopted, what should be the number and geographic definition of the LAPs?
3. Should participants be allowed to opt out of LAP scheduling and settlement, and if so, what would be the appropriate geographic granularity at which they could request scheduling and settlement for their loads?

The CAISO proposes to maintain the three-LAP design as proposed in the July 2003 filing, as well as the applicability of load aggregation as originally specified with no opportunity to opt out. There are three main reasons for this position.

First, the CAISO believes that the rationale for this position, as originally articulated in the July 2003 filing and recently summarized in a CAISO white paper on Congestion Revenue Rights (CRRs), is still valid.

Second, the primary motive for considering greater LAP granularity was the concern, first expressed in LECG's February 2005 report on the comprehensive MRTU design, that the three-LAP configuration could adversely affect the ability of loads within the CAISO control area to hedge the congestion costs associated with the LMP market design. The CAISO immediately acknowledged the legitimacy of this concern and noted that its forthcoming CRR Study 2 Report would provide some empirical evidence on the potential severity of this impact. Based on the results reported in the Final CRR Study 2 Report, prepared by LECG and released on August 24, 2005, the CAISO finds no evidence to suggest that the effect on congestion hedging of the three-LAP approach is severe enough to require a change to the July 2003 proposal. The CAISO notes, however, that its proposal for allocating CRRs to load-serving entities (LSEs) does allow for greater granularity in CRR release in order to redistribute congestion charges to LSEs as fully as possible. The last tier of the tiered allocation process allows LSEs to request CRRs that sink at the sub-LAP level,[26] thereby to obtain a partial hedge for the final increment of their CRR eligibility in the event that no additional LAP-level CRRs are feasible. See section 3.1 of this document for details.

Third, the written comments submitted by stakeholders in response to the CAISO's explicit request to comment on the LAP issue overwhelmingly support maintaining the three-LAP model without provision for opting out of load aggregation.

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[25] The exceptions are Metered Subsystems (MSS), Existing Transmission Contracts (ETCs), Transmission Ownership Rights (TORs) and Participating Loads.

[26] Sub-LAPs will be specified in a Business Practice Manual in 2006, prior to the mid-year running of the CAISO's proposed illustrative CRR allocation process. It is likely that such sub-LAPs will be roughly the same as the sub-LAPs utilized in CRR Study 2.

The CAISO notes that written comments received recently from stakeholders, representing many different types of load-serving entities and consumer interests, support maintaining settlement at the three LAPs. Most of these comments also support not having an opt-out provision. These entities specifically include: the Bay Area Municipal Transmission Group, the Energy Users Forum, the Northern California Power Agency, Pacific Gas & Electric, Silicon Valley Power, Southern California Edison and Strategic Energy.

State Water Project (SWP) has expressed concern about their pumps, which participate in the CAISO markets to provide demand response, having to schedule and settle at the LAP. In MRTU Release 1, the CAISO intends to model participating pumps and pump/storage facilities as generators with negative generation capabilities, and will therefore schedule and settle them at nodal prices. That is, pump/storage facilities can perform either as generators by injecting power into the grid, or as loads by consuming power from the grid, and therefore they are modeled in the CAISO markets as generators whose output can go negative when they are functioning as pumps. For Release 1 other participating loads such, as pumps, which are always functioning as loads, will be modeled in the same manner as pump/storage facilities. As a result, SWP's participating pump resources will be scheduled and settled at the individual nodal level rather than at the LAP level. The CAISO therefore believes that SWP's concerns are fully addressed. When the CAISO initiates its effort on the potential MRTU Release 2 elements in 2006, the CAISO will consider how, more generally, participating load that is not associated with pumps or pump/storage facilities will be modeled and settled as part of Release 2.

5.8 Credit of Net Revenues Associated with Marginal Losses Included in LMPs

Locational marginal pricing (LMP) is a key element of the MRTU design. Incorporating marginal losses in the LMPs provides the most accurate price signals for supply resources to schedule and operate in a manner consistent with reliable operation and economic efficiency and avoids paying artificially high prices to distant suppliers. At the same time, because marginal losses rise quadratically with transmission system flows, marginal losses exceed average losses by roughly a factor of 2. Therefore, the use of marginal losses in dispatch and pricing requires a mechanism for the CAISO to credit the net loss charges to market participants.

In its July 2003 comprehensive design filing the CAISO proposed to accomplish this credit by accumulating the hourly net loss charges in the CRR Balancing Account whose annual surplus would be paid to participating transmission owners to offset their transmission revenue requirements and thereby reduce the CAISO's access charges (TAC and WAC). Adding the net marginal loss charges to the CRR Balancing Account provided added insurance that CRR holders would be protected from any CRR revenue inadequacy resulting from outages or derates of transmission. Most importantly, paying the annual surplus from this account to the participating transmission owners to reduce transmission access charges offered a just and reasonable way to credit the net loss charges to the loads and exports who pay these charges in their LMP settlements. The CAISO reasoned that the use of these funds to reinforce CRR revenue adequacy could be minimized through proper enforcement of the simultaneous feasibility test in the CRR release process, and therefore most if not all of the net loss charges would flow back to loads and exports at the end of the year. In its October 2003 order on the CAISO's comprehensive design filing FERC approved this arrangement.

Since that time, however, many stakeholders have voiced concerns about the treatment of net loss charges and the management of these charges via the CRR Balancing Account. Specific concerns were expressed by entities with Existing Transmission Contracts (ETCs) and Transmission Ownership Rights (TORs) who serve demand (load or export) under these rights, are charged marginal losses, but are not beneficiaries of the reduction in TAC or WAC. Even the entities that were ultimately the beneficiaries of the reduction in TAC or WAC, objected to the long time delay between the charges they incur due to marginal loss surplus collected by the CAISO, and when it is credited back to them through reduced TAC or WAC. The CAISO therefore decided to consider ways it might address the expressed concerns without compromising the benefits of a marginal-loss-based implementation of LMP, in particular, the role full marginal losses play, when incorporated in LMPs, in providing scheduling and operating incentives that align with reliable grid operation and market efficiency.

The CAISO now proposes to separate the management of net loss charges from the CRR Balancing Account, and to credit the net loss revenues directly to the entities that serve demand (load and exports, including those served under ETCs or TORs) on each settlement statement, rather than at the end of the year indirectly through reductions in transmission revenue requirements of the participating transmission owners. Thus, for the period of each settlement statement the CAISO will calculate the total net loss charges collected for the system and divide this by the total MWh of demand (internal load plus exports) to determine a per-MWh loss refund amount. Each SC settlement statement will then include a credit equal to this per-MWh rate times its total MWh of demand. In essence for non-ETC and non-TOR demand this will be equivalent to a fixed reduction in each MWh of access charges the SC pays, and thus equivalent in concept to the FERC-approved approach using the CRR Balancing Account. It will dramatically reduce the impact of full marginal losses on market participants, however, because the CAISO will no longer collect the net loss charges and hold them only to refund them at a later time, but will instead use them to provide an immediate offset to each market participant's access charges. Moreover, by applying this to ETCs and TORs the CAISO addresses a concern expressed by those parties, specifically, that the CAISO's July 2003 proposal of using the transmission access charge reduction as the vehicle for crediting net loss charges would fail to compensate ETC and TOR holders for a share of net loss charges because these parties do not pay access charges. The present proposal resolves this concern.

It should also be underlined that this approach to the allocation of day-ahead marginal loss surplus is consistent with the allocation of marginal loss surplus in real-time implicit in CAISO's approved MRTU conceptual design (July 2003 filing). The real time surplus is part of the so-called real-time revenue neutrality account, which is allocated to Metered Demand.

One result of this proposal for allocation of day-ahead marginal loss surplus is that the net loss charges would not necessarily be available to help ensure the revenue adequacy of CRRs. As noted above, the CAISO can try to minimize this need through rigorous enforcement of simultaneous feasibility in the CRR release processes, but CRR holders will still face some risk of revenue shortfalls that can occur when there are substantial transmission outages or derates. Nevertheless, if there are concerns about reduction of the revenue adequacy insurance of CRRs as a result of CAISO's proposal, CAISO could consider a companion proposal to compute real-time net congestion charges collected by the CAISO and allocate any surplus (on a monthly or annual basis after reversing real-time ETC congestion charges) to the CRR Balancing Account.

Numerous stakeholders have commented in opposition to the collection of loss charges in excess of the average cost of system losses resulting from incorporating full marginal losses in LMPs. ETC and TOR holders have expressed the additional concern about their inability to benefit from the July 2003 proposal to credit net loss revenues via reductions in access charges. The CAISO believes that its current proposal addresses the concerns raised by these parties as much as possible consistent with the need to retain the use of marginal losses in the calculation of locational marginal prices under the MRTU design.