UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER06-___-000**

PREPARED DIRECT TESTIMONY
OF
LORENZO KRISTOV

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lorenzo Kristov. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am the Principal Market Architect, within the Department of Market and Product Development at the California ISO ("CAISO").

Q. Please describe your professional and educational background.

A. I have 15 years of experience in the electric utility industry, which began in 1991 working on demand forecasting at the California Energy Commission. In 1993 and 1994 I worked in Indonesia as a Fulbright scholar on the development of a commercial and regulatory framework to support private power investment. Then at the end of 1994 I returned to the California Energy Commission and for the next few years represented the Commission in all the retail electric restructuring proceedings and stakeholder working groups that were developing the rules for Direct Access. In 1999 I joined the CAISO in the Department of Market Analysis and shortly thereafter became part of the internal team formed to reform the CAISO's congestion management design. That effort was unfortunately interrupted by the crisis of 2000-2001, but at the end of 2001 I was able to reformulate the internal team and re-initiate the CAISO market redesign effort, which was the project known as Market Design 2002 or "MD02." Since that time

I have been one of a small group of internal experts working to finalize the CAISO Market redesign proposal, now renamed "MRTU." I received a master's degree in Statistics from North Carolina State University, and a Ph.D. in Economics from the University of California at Davis.

Q. Please describe your role in the development of the MRTU proposal.

A. I was Team Lead on the MD02 project when it first kicked off at the end of 2001, and was a primary contributor, along with several other internal experts, to the Comprehensive Market Design Proposal that the CAISO filed on May 1, 2002, both in terms of crafting the proposal itself as well as being a primary author of the documents that comprised the filing of the proposal. After FERC issued its initial order granting conceptual approval of the basic elements of the proposal and directed the CAISO to work with stakeholders to develop further details of the design, I had a leading role in the stakeholder working groups conducted through the fall of 2002. Then in 2003 I again gathered the internal team at the CAISO to incorporate the input we had obtained through the stakeholder working group process into an Amended Comprehensive Market Design Proposal that was filed in July of 2003. Again I was a primary author on the filing. Since that time the majority of my work effort at the CAISO has been to continue to resolve further design details and policy issues related to MRTU, working with internal experts, outside consultants such as LECG, and stakeholders in formal open working sessions as well as individual meetings with different stakeholder sectors. This continued effort has included participation in FERC technical conferences held in the first part of 2004, the stakeholder process on Existing Transmission Contracts also in 2004, and the broad, multi-issue MRTU policy resolution stakeholder process that occurred over most of 2005 and included as a major component the development of proposed rules for allocating Congestion Revenue Rights ("CRRs") to load-serving entities ("LSEs"). Finally, I should also note that I have been a "subject-matter expert" contributor to the MRTU Tariff that is now being filed.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is intended to provide a thorough overview of the MRTU market design and its components and, in so doing, to explain the objectives of the CAISO Market redesign effort and the rationale behind the specific design of the elements of MRTU. My testimony is intended to be comprehensive rather than extremely detailed, however, and therefore my testimony is complemented, expanded upon and supported by the accompanying testimony of several other expert witnesses.

II. OVERVIEW AND RATIONALE OF THE MRTU MARKET REDESIGN

Q. Please explain the relationship between the MRTU project and the comprehensive redesign of the CAISO markets.

A. The CAISO project known as "Market Redesign and Technology Upgrade" or "MRTU" is comprised of two major initiatives. The "MR" initiative, which is the subject of my testimony, is the comprehensive redesign of the CAISO markets as embodied in the Tariff amendments being submitted to the Commission concurrent with this testimony. The "TU" initiative, which is not a subject of this testimony, is the overhaul and replacement of the CAISO Market systems and software, which the CAISO would have needed to do even if we were not redesigning the markets. Therefore, when I use the term "MRTU" and other terms like "MRTU Tariff" or "MRTU design" in the course of this testimony, I am referring specifically to the CAISO Market redesign.

Q. Will the CAISO Market redesign incorporate all design elements that were identified in the stakeholder review process as desirable or potentially desirable when the MRTU design is first implemented?

A. No. As is the case with any large-scale project of this nature, the scope and design of the project must be "frozen" well in advance of the target implementation date. The CAISO had to recognize that some of the policy issues and design details were still in process of resolution while software and systems were being developed at the same time. Therefore, it was necessary to identify a subset of elements and design changes that would not be included in the "Release 1" design, upon start-up of the new markets, but would be incorporated in a subsequent "Release 2" for implementation at a later date. Although the timing of Release 1 has now been delayed from February 2007 to November 2007, it is still necessary to maintain the original scope for Release 1 and not expand it, as discussed more fully in the testimony of Brian Rahman. In this regard it is important to point out that the Release 1 design will be a fully functional and internally consistent market design. The concept of "freezing" the design has not precluded making changes where such changes were determined to be needed to ensure the successful functioning of the new markets. That being said, while the elements and changes deferred to Release 2 are not critical for the success of Release 1, they will enhance the efficiency of the markets or provide additional functionality desired by Market Participants. The CAISO has not yet set an implementation date for Release 2, but does intend to initiate design activities on the Release 2 elements both internally and with stakeholders in the first part of 2006. At various points in this testimony I will refer to some of these Release 2 elements.

Q. Why did the CAISO undertake a comprehensive redesign of its markets, and how did the redesign effort evolve into the proposal being submitted in this filing?

A. At the outset, it is crucial to understand that the central objective of the MRTU market redesign has always been to eliminate the problems inherent in the zonal Congestion Management design that the CAISO and the California Power Exchange ("PX") markets were based on. The CAISO's efforts to reform Congestion Management go back to the beginning of the year 2000, when the CAISO initiated its "Congestion Management Reform" or "CMR" process in response to a Commission order issued in January 2000, which directed the CAISO to pursue a comprehensive replacement to its present Congestion Management approach. *California Independent System Operator Corporation*, 90

FERC ¶ 61,006 (2000). Unfortunately, beginning in the summer of 2000, California began to experience the well-known electricity crisis, and this quickly became the primary focus of attention of the CAISO and other parties in California. As a result, although the CAISO's CMR effort did culminate in a final report and recommendations in January 2001, it was not possible for the CAISO to implement a comprehensive effort to replace its Congestion Management system at that time.

One year later, the crisis conditions had subsided sufficiently to allow the CAISO and the stakeholders to return to the matter of reforming the CAISO markets, with particular focus on addressing the Congestion Management design. Thus, in January 2002, the CAISO initiated the "Market Design 2002" or "MD02" project, which has evolved into the MRTU project. In this process the key filing milestones have been the CAISO's May 1, 2002 Comprehensive Market Design Proposal, the July 22, 2003 *Amendment to the Comprehensive Market Design Proposal* filing, the May 13, 2005 *Further Amendments to the Comprehensive Market Redesign Proposal* filing, and the present MRTU Tariff filing.

Although the CAISO Market redesign has evolved considerably since the May 2002 filing, the fundamental structural elements of the redesign have remained constant because they derive from the core objective of reforming the CAISO's Congestion Management design. At the commencement of MD02 the CAISO recognized that properly reforming Congestion Management would require establishing rules and procedures for allocating and pricing transmission and for clearing and pricing energy that are consistent across market time frames – an attribute that was crucially absent in the original design of the CAISO. The market time frames relevant to the CAISO can most logically be thought about by starting with the Real-Time balancing market, where the practical impacts of the laws of physics cannot be avoided, and working backward to the Hour-Ahead Scheduling Process ("HASP"), the Day-Ahead Market and, beyond that, to the process for awarding transmission rights. The rules and procedures for transmission allocation and pricing should be consistent across these markets. The main problem with the CAISO's original zonal Congestion Management design was that it deliberately did not require consistency between the forward markets (Day-Ahead and Hour-Ahead) and the Real-Time market. A primary objective of the MRTU design therefore, has been to remedy this deficiency.

Q. You mentioned one problem with the CAISO's original market design. Were there other problems with the original market design that the MRTU design addresses?

A. Yes. In addition to the main problem with respect to the CAISO's original zonal Congestion Management design that I just mentioned, there are a number of other flaws in the original CAISO market design – which is, with few modifications, still the framework that the CAISO operates under today – that MRTU will address.

- Fundamentally, the original design of the CAISO and the PX defined the CAISO's two main core functions – to operate the grid reliably and to provide non-discriminatory access to the grid – extremely narrowly. Specifically, it restricted the scope of reliable grid operation to the Real-Time Market itself, and severely limited the CAISO's Day-Ahead and Hour-Ahead roles to performing the highly simplified zonal Congestion Management function, plus the awarding of Ancillary Services (AS) and scheduling of Reliability Must-Run ("RMR") units. After the original CAISO start-up, the annual auction of Firm Transmission Rights ("FTR") was added to the CAISO's scope of responsibilities. The CAISO was precluded by design from facilitating any additional Day-Ahead and Hour-Ahead energy trading and unit commitment activities on the principle that these would be accomplished most efficiently and in a manner consistent with reliable grid operation through the decentralized actions of the Scheduling Coordinators, supplemented with the PX which provided a Day-Ahead energy market that was, like the CAISO's Day-Ahead Congestion Management, blind to Congestion within the CAISO grid. The next few points explain problems that were built upon this fundamental design approach.

- In the original Day-Ahead and Hour-Ahead markets, all but a handful of designated "inter-zonal" transmission limits are ignored based on the assumptions, first, that these other "intra-zonal" limits would be commercially insignificant and easily managed by grid operators in real time, and second, that whenever an intra-zonal constraint became significant it could readily be re-designated as an inter-zonal constraint to be incorporated in the Day-Ahead and Hour-Ahead processes. Both assumptions have proved to be problematic, as evidenced by the well-known "Miguel congestion" problem that arose a few years ago. At that time the connection of new generation at the border with Mexico caused chronic, costly intra-zonal congestion due to a bottleneck at the Miguel substation. The best efforts by the CAISO and stakeholders to move the management of Miguel congestion into the Day-Ahead and Hour-Ahead markets by creating a new zone went nowhere, due to both the complicated grid topology in the area and concerns by many parties about how congestion cost allocation would be altered. Thus the idea of creating new zones proved to be unworkable. Continuing concerns about the "infeasible schedules" the CAISO accepts in today's Day-Ahead and Hour-Ahead markets arise directly out of the differential treatment of inter-zonal and intra-zonal constraints.

- The original design includes a "market separation" rule which prevents the CAISO from facilitating Day-Ahead and Hour-Ahead energy trading, and as a result prevents the CAISO from clearing Day-Ahead and Hour-Ahead congestion efficiently. This element was based on the principle that the Scheduling Coordinators would perform efficient Day-Ahead and Hour-Ahead Congestion Management themselves. But this could be plausible only in conjunction with the previous point, *i.e.*, the simplified zonal design, because if all the transmission limits are enforced in Day-Ahead and Hour-Ahead the market separation rule would chronically cause the

CAISO to exhaust economic transmission Bids and resort to non-economic or pro rata Congestion Management. The CAISO's groundwork in developing the MRTU design quickly recognized that economic Day-Ahead Congestion Management that utilizes a realistically detailed network model cannot be separated from CAISO-facilitated trading of energy among Scheduling Coordinators ("SCs").

- The original design precludes the CAISO from performing optimal security constrained unit commitment and from issuing any unit commitment instructions in the Day-Ahead or Hour-Ahead timeframes except in the context of RMR. The CAISO has since recognized that Day-Ahead unit commitment is a crucial reliability function rather than a separable, pure market activity, as shown by the need to rely on the Day-Ahead must-offer waiver denial process in recent years as an imperfect substitute for an optimal Day-Ahead unit commitment process.

Q. What are the main structural components of the MRTU market design that will address these problems?

A. Based on the concepts and rationales described above, the present Tariff filing, like the May 2002 and July 2003 filings before it, is built around the following fundamental structural elements:

(1) a "Full Network Model" or "FNM" to be used in all CAISO markets – the Real-Time, Day-Ahead, and transmission rights markets – that reflects the topology of the CAISO grid and the associated transmission constraints

accurately. The FNM, in conjunction with Security Constrained Unit Commitment ("SCUC") and Security Constrained Economic Dispatch ("SCED") algorithms, comprise the functional core of the MRTU market design. The consistent enforcement of the FNM across all CAISO market time-frames is key to ensuring that market outcomes reflect and support the efficient and reliable Real-Time operation of the transmission grid;

(2) an "Integrated Forward Market" or "IFM" optimization, which utilizes the SCUC to commit resources, manage Congestion, balance Energy Supply and Demand, and procure AS in the most efficient, integrated manner based on economic Bids submitted by Market Participants. Although the term "IFM" applies specifically to the Day-Ahead Market, essentially the same optimization algorithm will be used in the Real-Time balancing market and the Real-Time pre-Dispatch process referred to as the "Hour-Ahead Scheduling Process" or "HASP." The IFM design also incorporates specific provisions to allow entities to engage in long-term bilateral contracting and avoid exposure to the short-term markets by "self-scheduling" their bilateral transactions in the Day-Ahead Market and in the HASP. In this context, I will also discuss certain narrow topics such as the use of Load Aggregation Points (LAPs) for scheduling and settling most Demand within the CAISO Control Area, and the treatment of Constrained Output Generation ("COG") and Intermittent Resources;

(3) a "Residual Unit Commitment" or "RUC" process that enables the CAISO to identify and commit on a Day-Ahead basis additional capacity that will

be needed in Real-Time to meet the CAISO's Demand Forecast, but may not have been committed or scheduled in the financial Day-Ahead IFM;

(4) the "Locational Marginal Pricing" or "LMP" approach for managing congestion and determining marginal energy prices for each settlement period that accurately reflect the least cost, based on Market Participants' submitted Bids, of serving the next MWh of demand at each location on the CAISO grid, including the cost of congestion and transmission losses;

(5) financial instruments called "Congestion Revenue Rights" or "CRRs" for hedging the Congestion Charges associated with LMP, to be released on both an annual and a monthly basis through an allocation process to LSEs and through an auction open to all creditworthy parties;

(6) Market Power Mitigation ("MPM") procedures designed for compatibility with the LMP market design, which recognize that the transmission system in California was built on a vertically-integrated utility model and not with MRTU markets in mind; and

(7) explicit linkages between resource adequacy requirements that will apply to LSEs and the CAISO markets. These linkages are captured in rules and procedures whereby supply capacity that is procured by LSEs under state and local regulatory requirements is required to participate in the CAISO Markets starting with the Day-Ahead timeframe, to ensure that the "adequacy" achieved via forward procurement translates into day-to-day adequacy for operating the transmission system.

Q. Which of these structural components are the focus of your testimony, and which components are discussed in the testimony of other witnesses?

A. My testimony focuses primarily on components (1) through (4), and to a limited extent (5). It expands upon these components and lays out in a schematic fashion the various policy and design issues that have been addressed by the CAISO and the stakeholders in the thorough and intensive multi-year process leading up to the present filing. In addition, my testimony discusses the treatment under MRTU of Existing Transmission Contracts ("ETCs"), Transmission Ownership Rights ("TORs"), and the Converted Rights of New Participating Transmission Owners. Other witnesses are submitting testimony that fully cover components (5) (Susan Pope and Scott Harvey), (6) (Keith Casey) and (7) (Mark Rothleder). In addition, there is separate testimony on the topics of (a) price determination, payments to suppliers and cost allocation (Farrokh Rahimi), and (b) "Metered Subsystems" ("MSS") (Kristov, Rothleder and Rahimi). Both of these additional topics comprise multiple sub-topics that cut across most of the seven major components listed above. To provide a complete picture of the testimony being submitted with this filing, I should also mention testimony by Scott Harvey of LECG which discusses the MRTU design in general and also revisits several issues that were raised in a February 2005 report on the MRTU design by Harvey, William Hogan and Susan Pope of LECG and discusses how the CAISO has modified the MRTU design to address these issues. The final piece of testimony is being submitted by Brian Rahman and deals with MRTU software and implementation matters.

III. DETAILS OF THE COMPONENTS OF THE MRTU DESIGN

A. <u>The Full Network Model, Security Constrained Unit Commitment And Locational Marginal Pricing</u>

Q. Please describe the core elements of the MRTU design and why they are so crucial to the primary objectives of the CAISO Market redesign.

A. There are three complementary elements that form the basis of the MRTU design: the Full Network Model ("FNM"), the Security Constrained Unit Commitment ("SCUC") process which is the optimization engine of the MRTU markets (except for the five-minute Real-Time Dispatch which utilizes a Security Constrained Economic Dispatch ("SCED") algorithm), and Locational Marginal Pricing ("LMP"). Together these three elements form the core of the MRTU design. The FNM is the element that ensures consistency between transactions in the CAISO markets and the physical operating needs of the grid, and thus eliminates the problem of "infeasible schedules" inherent in the current zonal design. The FNM is used in the allocation and auction of CRRs as well as in the CAISO's spot markets, so that these congestion hedging instruments reflect as closely as possible the grid constraints that will actually be enforced in the spot markets. The SCUC is the market optimization process, which performs Congestion Management and clears Energy Supply and Demand in an integrated fashion, performs Unit Commitment, local market power mitigation and reliability Dispatch, and optimizes the provision of AS. The SCUC is used in conjunction with the FNM in the Day-Ahead IFM, the RUC process, the HASP and the Real-Time Market. Finally, LMP is the methodology for pricing Energy and charging for Congestion on the grid, based on locational or "nodal" marginal energy prices at each node of the FNM as calculated by the SCUC optimization. The nodal LMPs paid to Supply resources provide the correct signals to these resources to operate in a manner consistent with reliable grid operation and economic efficiency. Taken together these three elements address the primary objectives of the CAISO Market redesign, namely, to replace the current zonal market design with a system that ensures consistency between the market outcomes and the operational needs of the grid, as well as consistency in pricing and transmission allocation across the CAISO Market time frames.

Q. Please describe the FNM in greater detail.

A. The FNM is a detailed mathematical representation of the physical transmission system that the CAISO operates, and as its name suggests it accurately represents the constraints and interfaces of the CAISO Controlled Grid. It also incorporates a representation of other control areas within California that are not part of the CAISO Controlled Grid, as well as the interconnections between the CAISO and control areas in neighboring states. Initially the FNM will represent control areas in neighboring states in an "open loop" format that treats each intertie independently of the others and does not try to represent power flows in these external areas. Eventually, however, the open loop model will be replaced with a "closed loop" representation that captures external electrical connections between the various interties into the CAISO Control Area. This will allow the CAISO to estimate and manage parallel path or "loop" flows in coordination with other control areas in the western region, in a manner that is more accurate than is possible today.

Because the FNM will accurately locate all supply resources and Demand in relation to transmission facilities and the flow limits on those facilities, the FNM is the means by which the SCUC algorithm ensures that accepted Day-Ahead IFM Schedules, RUC awards, HASP Schedules and Real-Time Dispatch instructions are feasible and that the commitment and Dispatch of resources is optimally efficient. In addition to these items, the nodal LMPs are the other main output of the SCUC FNM-based optimization. Finally, the FNM is also used in the CRR allocation and auction processes to ensure that released CRRs are simultaneously feasible with respect to the same network topology that will be used to generate Congestion Charges in the CAISO markets, and thus will generate sufficient revenues to be an effective congestion hedge for CRR Holders.

Q. What role does the FNM play in price determination?

A. Because FNM represents that network topology and constraints which govern Real-Time Energy flows on the grid, using it in conjunction with the SCUC optimization, results in nodal LMPs that reflect the cost of serving one additional MWh of Demand at each grid node, including the costs of Congestion and transmission losses. As the Commission explained in an order issued on October 28, 2003,[1] "by using the Full Network Model in conjunction with LMP, the

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1 *California Independent System Operator Corp.*, 105 FERC ¶ 61,140 ("October 28, 2003 Order"), *reh'g denied*, 105 FERC ¶ 61,278 (2003).

CAISO will be able to use price Bids to calculate the lowest cost way of meeting an increase in load at each location on the network, taking transmission limits into account." October 28, 2003 Order at P 48.

Q. Please describe, generally, the nature of the nodal LMPs determined in the MRTU markets.

A. As I mentioned earlier, Locational Marginal Pricing ("LMP") is an approach to managing congestion and determining marginal energy prices for each settlement interval that accurately reflects the least cost, based on Market Participants' submitted Bids, of serving the next MWh of demand at each location on the CAISO grid, including the cost of congestion and transmission losses.

Under MRTU, the nodal LMPs can be broken down into three components: a reference Energy price (*i.e.*, system energy absent transmission constraints and losses), plus components reflecting the cost of Marginal Losses and the cost of Congestion. A detailed description of how these three components are determined based on energy Bids is set forth in the testimony of witness Dr. Farrokh Rahimi.

Q. Please describe the considerations that led the CAISO to develop LMP.

A. Going back to the original reasons I described earlier why the CAISO undertook a comprehensive redesign of its spot markets – the primary of which was to replace the problematic zonal market design – there were a few basic requirements that led the CAISO to the decision to adopt LMP. First was the requirement that congestion management should be based on a realistic model of the transmission grid with all transmission limits enforced – hence the FNM, to be used in the Day-Ahead, Hour-Ahead and Real-Time processes.

Second was the recognition that the original "market separation rule" would not be compatible with economic Congestion Management using a realistic model of the grid and enforcing all constraints. That is, trying to resolve congestion on a complex meshed network while keeping each SC's hourly schedule individually balanced – in other words, without being able to offset a decremental adjustment for one SC against an incremental adjustment for another SC – would chronically lead to the exhaustion of economic Bids and the need to impose non-economic pro rata curtailment, ultimately resulting in the more severe curtailment of submitted Schedules than would be necessary without the market separation rule. Thus, it became apparent that there could be no distinction, in a FNM-based Congestion Management approach, between performing Congestion Management and clearing Energy markets. This conclusion was perfectly compatible with another objective of the CAISO Market redesign effort, namely, to create a transparent Day-Ahead Market for Energy to replace the defunct PX.

Third, the CAISO started the Market Design 2002 effort, which later became MRTU, with the explicit recognition that we must learn from the experiences of other ISOs, and avoid designing something that was unique to California except where we identified a unique California circumstance that required us to design a new solution. It was of utmost importance, following the recent power crisis in California, to redesign the CAISO markets based on approaches that had been demonstrated to work successfully, and to draw upon the collective intelligence of people working at or with the other ISOs, all of whom where addressing the same fundamental requirements faced in California. Thus, one of the first tasks in redesigning the CAISO markets was to consult with market design personnel at PJM, NYISO and ISO-NE and learn about how their market designs worked and what changes were being developed for those designs.

Based on the above considerations, it quickly became apparent that the LMP approach would meet all the CAISO's design objectives and offered an associated large body of practical experience and expertise to draw upon. As a result, the management of congestion and determination of marginal Energy prices through LMP has been a bedrock element of the ISO's market redesign process from the beginning. It was the basis for the CAISO's initial May 1, 2002 Comprehensive Market Design Proposal and for every subsequent MRTU filing.

Q. Did the commission approve the CAISO's proposal to center its market redesign around the LMP approach?

A. Yes. The Commission approved the basic principle of LMP in the October 28, 2003 Order. Therein, the Commission agreed with the CAISO that managing congestion using the LMP approach would constitute a vast improvement over the CAISO's current congestion management system, because it would promote more efficient use of the transmission grid, promote the use of the lowest-cost generation, provide for transparent price signals, and enable the CAISO to operate the grid more reliably. October 28, 2003 Order at PP 49-50.

Q. Please explain the problems with the CAISO's current Congestion Management system, and how the implementation of LMP in conjunction with the SCUC and FNM will eliminate these problems.

A. The CAISO currently employs a zonal Congestion Management model which explicitly models only transmission constraints between three large congestion zones, as well as interties with adjacent control areas, but does not model the hundreds of "intra-zonal" transmission constraints. As a result of this design the CAISO's Day-Ahead and Hour-Ahead Congestion Management system cannot determine whether submitted schedules are "feasible," that is, whether they can actually flow in real time without violating intra-zonal constraints. Instead, the current design relies on CAISO operators, in Real-Time, to detect and manage intra-zonal Congestion. In other words, lacking the capability and the authority under the current market design to modify submitted schedules in Day-Ahead and Hour-Ahead to prevent intra-zonal Congestion, the CAISO accepts "infeasible" Day-Ahead and Hour-Ahead schedules which, in turn, creates an operational burden on the CAISO's operators in Real-Time to manage intra-zonal congestion in a manner that ensures the reliable operation of the grid. This is a difficult and demanding process that commands a disproportionate share of CAISO operators' time, forces them to scramble in Real-Time to keep the grid running reliably, and impinges on their other responsibilities.

The combination of LMP, FNM and SCUC, particularly as applied in the Day-Ahead IFM and the HASP under MRTU, will address these problems because it will ensure that all schedules are feasible with respect to all transmission constraints, as well as generator performance limitations. The distinction between intra-zonal and inter-zonal Congestion will be eliminated by using a FNM that models all constraints, and enforcing the FNM in the IFM and HASP will prevent the CAISO market system from accepting infeasible Day-Ahead and Hour-Ahead schedules.

Viewed another way, this also means that each generator's location and its effectiveness in addressing each constraint will be considered when resolving Congestion and determining the nodal price for that generator, thus aligning the generator's accepted Schedule and any subsequent Dispatch Instructions, as well as the price at which its Energy is settled, with the operating needs of the grid. In contrast, today's zonal design ignores the differential effectiveness of differently located generators within each zone when attempting to resolve Congestion. By accepting only feasible schedules in Day-Ahead IFM and HASP, the implementation of LMP with the FNM and SCUC will make it easier for CAISO operators to run the grid and thus promote increased system reliability.

Q. Has CAISO considered the effects of LMPs on the volatility of prices?

A. Yes. Since 2002 when the LMP-based market redesign was first proposed the CAISO has been continually conducting studies to simulate hourly LMPs for the CAISO grid. The first of these was published in September 2002. Others followed in October 2003, July 2004, and August, October and November 2005. The CAISO has discussed these studies with stakeholders, and the study reports are all available, with detailed explanations of the study methodologies, on the CAISO web site. The CAISO intends to continue performing and publishing LMP studies all the way up to MRTU start-up. Through these studies tthe CAISO is simulating and analyzing price variations under the full range of realistic grid conditions, so that the CAISO and Market Participants can form realistic expectations about how LMPs will vary in practice.

Moreover, the CAISO has structured the MRTU proposal to include several elements that mitigate the impacts of price volatility under LMP without compromising the effectiveness and the benefits of the LMP design. The three main elements are: (1) Local Market Power Mitigation (LMPM), which is discussed in the testimony of Keith Casey; (2) Congestion Revenue Rights ("CRR") for hedging the most significant component of price volatility, congestion costs; CRRs are discussed in the testimony of Scott Harvey and Susan Pope; and (3) Demand settlement at Load Aggregation Point ("LAP") prices, which are Demand-weighted averages of nodal LMPs over specified areas of the grid. I will discuss LAP-based Demand settlement in more detail below.

Q. How are transmission losses incorporated in the MRTU markets?

A. Transmission losses are incorporated explicitly into the SCUC and SCED optimization, which utilize an AC optimal power flow so that the resulting Dispatch of resources to balance demand includes sufficient supply to cover transmission losses, and the resulting nodal LMPs include the marginal cost of losses.

Q. Why is it important to account for losses in this manner?

A. Referring back to the earlier discussion of what motivated the comprehensive CAISO market redesign, it has consistently been a top priority of the redesign to send price signals to supply resources that accurately reflect the impacts on the grid of the power they produce and the cost of delivering the power from the location where it is generated or imported into the grid to the location where it is removed from the grid to serve Demand. The costs of delivering power are measured in terms of congestion and transmission losses, both of which are incorporated in the LMPs that will be calculated and used for settlements in the MRTU markets. By incorporating marginal transmission losses in the LMPs, the LMPs at each node will reflect the marginal increase in the cost of transmission losses due to delivering one additional MWh of Energy to that node in the least-cost manner. By paying supply resources their nodal LMPs with marginal losses included the CAISO sends them price signals that correspond to operating levels consistent with the optimal Dispatch of resources to meet Demand.

Q. What are the settlement impacts of incorporating marginal losses in the LMPs?

A. Incorporating marginal losses in the LMPs causes the CAISO to collect more money than is necessary to cover the actual cost of losses. Transmission losses are reflected in the IFM Schedules and in the Real-Time Dispatches by having more MWh of Supply than Demand in the power balance to compensate for the

MWh lost in moving the Energy over the grid. Yet after the money is collected from the Demand and paid to the Supply, there is still net revenue in the hands of the CAISO due to the Marginal Loss components of the LMPs, so the CAISO must have a way to distribute this revenue in a manner that is equitable and does not compromise the effectiveness of the price signals.

Q. Has the CAISO determined how to distribute these net marginal loss revenues?

A. Yes. During the MRTU stakeholder process in 2005 the CAISO proposed to track the net revenues on an hourly basis, and then to distribute the funds through each SC's settlement statement by crediting a fixed per-MWh amount to the total metered Demand plus Real-Time Interchange export schedules of each SC.

Q. Did the Commission approve the incorporation of marginal losses in the LMPs?

A. Yes, in the October 2003 Order the Commission approved the CAISO's proposal to incorporate marginal losses in the calculation of LMPs. October 28, 2003 Order at P 77.

B. Load Aggregation Points

Q. Please describe the rationale for using aggregations of network nodes called Load Aggregation Points (LAPs) for Demand scheduling and settlement.

A. The primary reason for the use of LAPs for Demand scheduling and settlement is to prevent unfair financial impacts to consumers located in constrained areas of the grid due to the transition to nodal pricing under MRTU. It is unfair for consumers in such “load pockets” to be subject to high nodal prices under LMP because it would be the result of a change in industry structure and regulatory regime rather than the actions or choices of such consumers. Moreover, this potential unfairness must be addressed by the CAISO at the wholesale level. It cannot be addressed at the retail level because customers within a given load pocket may well be served by different types of LSEs under different regulatory regimes – investor-owned utilities, direct access electric service providers (ESPs) and municipal utilities, with the result that customers within each load pocket would fare differently depending on the type of LSE that serves them. By using aggregated pricing at the wholesale level such disparities will be avoided.

A secondary reason for adopting aggregated Demand scheduling and settlement is a practical one. For LSEs that have hundreds or thousands of customers spread over potentially large areas, scheduling by individual node when there are over 3000 nodes in the CAISO network would be an implementation complexity that would make the change to LMP extremely burdensome. Moreover, once the decision to schedule Demands at aggregations of nodes is made, then it is essential to settle such Demands at prices that correspond to their scheduling points to maintain proper incentives for accurate scheduling.

Finally, in support of the decision to use LAPs for Demand scheduling and settlement, there is general agreement among experts and those who operate markets based on LMP that the most important element in achieving the operational benefits of LMP is to settle supply resources at nodal prices, and that it is much less important to settle Demand at nodal prices. In fact, Demand Settlement at aggregated prices is used by the other ISOs that operate LMP markets with no adverse impacts. In addition, with regard to incentives for increasing Demand responsiveness, settlement based on time-varying prices is far more effective than settlement at spatially-varying prices. The CAISO therefore believes that it can implement LAP settlement and pricing for Demand without compromising the effectiveness of the new LMP markets.

Q. Please elaborate on the reason why it would be unfair to charge nodal prices to Demand located in load pockets.

A. California's transmission infrastructure was designed and constructed under an integrated utility industry regime and regulatory framework that never anticipated either locational pricing or the unbundling of the generation function of electricity from the transmission function. Under the former vertically-integrated utility framework, decisions to build transmission were based on the presumption that: (1) consumers would not be charged different rates based on the impact of transmission constraints, and (2) the integrated utility should plan investment in generation and transmission infrastructure in an integrated fashion, substituting one for the other to meet their Demand in a cost-effective manner. As a result, the structure in certain areas of the grid unduly limits the ability of consumers in those areas to benefit from the primary objective of electric restructuring, namely, access to competitive generation supplies. Moreover, the original design of the CAISO and the PX markets retained the practice of settling internal Demand at wholesale prices that were calculated for large geographic areas rather than locally. Because of this legacy, large numbers of consumers are still situated within load pocket constraints. Under these circumstances, it would be patently unfair immediately upon changing the CAISO Market design to LMP, to subject these consumers to locational prices when they are unable to enjoy the benefits of competition.

Q. Did the Commission at any point review and comment on the CAISO's proposal to settle Demand at aggregated prices?

A. Yes. In the CAISO's July 22, 2003 comprehensive market redesign filing, the CAISO proposed to use three LAP zones, based on the service territories of the three major California Investor-Owned Utilities ("IOUs"), for scheduling and settling Demand. In the October 28, 2003 Order, the Commission explicitly accepted the CAISO's conceptual LAP proposal, stating that the CAISO's proposal represented a "reasonable and simplified approach to introduce LMP pricing, while minimizing its impact on load." The Commission also concluded that the CAISO's LAP proposal was "consistent with load aggregation proposals the Commission has approved in the northeastern ISO and RTO markets and with the Commission's White Paper." October 28, 2003 Order at P 65.

Q. What other guidance have FERC orders on MRTU given to the CAISO regarding LAPs?

A. In the July 1, 2005 Order[2], the Commission, noting stakeholder concerns about the number of LAP zones, "... agree[d] with intervenors that the currently proposed LAP zones should be further disaggregated to provide more accurate price signals and assist participants in the hedging of congestion charges…" (July 1, 2005 Order at P 35), and encouraged the CAISO, in reviewing the results of its CRR Study 2, to consider how the sizing of the LAP zones "may impede the ability of market participants to effectively hedge congestion costs due to the reduced availability of CRRs that result from larger zone definitions." July 1, 2005 Order at P 37. Several parties sought rehearing or clarification on the matter of the number of LAP zones, and in response, the Commission clarified in its September 19, 2005 Order on Rehearing,[3] that it would await the CAISO's further proposal before ruling on the number of LAPs. In response to an argument by SCE that increasing the number of LAPs would require complex and costly software and process modifications and jeopardize the MRTU start-up date, the Commission stated that, "the CAISO is directed to re-examine its proposed LAP zones, taking into account the results of CRR Study 2 and its stakeholder

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[2] *California Independent System Operator Corp.*, 112 FERC ¶ 61,013 (2005) ("July 1, 2005 Order").

[3] *California Independent System Operator Corp.*, 112 FERC ¶ 61,310 (2005) ("September 19, 2005 Order").

process. If this re-examination shows that there are efficiencies in proceeding with LAPs that are smaller than SCE's service territory and the CAISO makes such a proposal, then SCE may argue against and demonstrate the specific barriers to its implementing additional LAPs ..." September 19, 2005 Order P 21.

On a related issue, the July 1, 2005 Order further stated that, "At a minimum, however, each wholesale customer should have the option of establishing, as a separate zone, the set of nodes where it receives energy." July 1, 2005 Order P 37. The Commission reconsidered the latter issue in the November 14, 2005 Order,[4] however, and concluded that for Release 1 of MRTU it would not require the CAISO to allow wholesale customers to establish separate LAP zones. November 14, 2005 Order at P 1.

Q. How many LAP zones does the CAISO now propose to use in scheduling and settling Demand?

A. The current proposal retains the original proposal to use three "Default LAPs" defined to coincide with the transmission service territories of the three investor-owned utilities, PG&E, SCE and SDG&E. In addition, based on the input received from the Commission and stakeholders, and taking into account the results of the CRR Study 2, the CAISO has modified its original proposal to provide more granular Demand scheduling and settlement in a number of specific

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[4] *California Independent System Operator Corp.*, 113 FERC ¶ 61,151 (2005) ("November 14, 2005 Order").

circumstances. First, there are distinct LAPs for Metered Subsystems referred to as "MSS-LAPs," which are discussed in greater detail in the separate testimony being submitted with this filing on MSS. Second, Demand for which Energy delivery to the Demand location is provided under ETC or TOR rights will be settled based on custom LAP prices analogous to those for MSS. Third, Participating Loads will be separated out of the Default LAPs and will schedule at their nodal locations and settle at the corresponding nodal LMPs. Fourth, the CRR Allocation and Auction will allow parties to obtain CRRs that have a "sub-LAP" as their source or sink. These sub-LAPs will be defined, based on further LMP studies the CAISO is conducting, as sub-areas of the three Default LAPs within which the LMPs are relatively uniform due to minimal congestion within each sub-LAP. Further details on the use of sub-LAPs in connection with CRRs is provided in the testimony of Dr. Susan Pope and Dr. Scott Harvey. Other than the exceptions I just identified, all Demand within the CAISO control area will utilize the three Default LAPs. I note in particular that the current tariff, consistent with the Commission's findings in the November 14, 2005 Order, does not have provisions that generally would allow Demand the discretion to opt-out of the Default LAPs. This limitation is appropriate because more general discretionary opting out of the Default LAPs would defeat the purpose of using the Default LAPs by allowing Demand at low-priced nodes to opt out, hereby removing the lower LMPs from the LAP prices and raising the LAP prices paid by the remaining Demand.

Q. Do you believe that the CAISO's current proposal to use three large Default LAPs is reasonable?

A. Yes. There are a number of reasons why it is appropriate to settle most (but not all) Demand at three Default LAPs based on the service territories of the major California IOUs. First, the local constraints in the grid differ in extent and severity among the three IOUs, each of which had its own approach to optimizing the tradeoff between constructing new transmission and acquiring new generation to assure that all of its Demand could be served, and therefore it is appropriate to use three IOU-based LAPs as the primary aggregation approach for most customers. Moreover, as I explained above, the California transmission grid was not built with the expectation that the system would be used to support an LMP-based market. Therefore, further disaggregation of the LAPs for the initial release of MRTU could result in extremely high prices to consumers in congested areas resulting from constraints in a transmission system that was designed and constructed under an entirely different regulatory regime. Not only would imposing such high prices on these consumers through a market design change be inequitable, it could also create significant political resistance to LMP-based markets in California. A number of entities, including the CPUC and many LSEs, support maintaining Demand scheduling and settlement at the Default LAPs proposed by the CAISO.

Second, the primary motive for the Commission's findings favoring greater LAP granularity for all Demand was the concern, first expressed in LECG's February 2005 MRTU Report on the comprehensive MRTU design, that larger LAPs could adversely affect the ability of Demand 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 found 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. This issue is discussed in greater detail in the testimony of Dr. Scott Harvey and Dr. Susan Pope.

Finally, the CAISO's proposal for allocating CRRs to all LSEs allows for greater granularity in the release of CRRs 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, thereby obtaining a partial hedge for the final increment of their CRR eligibility in the event that no additional LAP-level CRRs are feasible.

The specific sub-LAPs available during MRTU Release 1 will be defined as part of the MRTU stakeholder process in 2006, prior to the mid-year running of the CAISO's proposed illustrative CRR allocation process. The CAISO anticipates submitting details on sub-LAP definition in a subsequent 205 filing prior to the MRTU Implementation Date. The CAISO anticipates that such sub-LAPs will be roughly similar to the sub-LAPs utilized in CRR Study 2.

Q. Please describe and provide the rationale for clearing LAP Demand Bids at the LAP level.

A. Inherent in the concept of using LAPs for scheduling and settlement, as described in the CAISO's July 22, 2003 proposal, is that in most cases, SCs would Bid, Self-Schedule and be settled for Demand at one of the three IOU-LAPs without reference to the specific network nodes at which that Demand will withdraw energy. The IFM optimization, however, requires Demand to be located at individual nodes, so in the July 2003 filing the CAISO proposed to distribute submitted Demand Bids and Self-Schedules to individual nodes using Load Distribution Factors ("LDFs") for the purpose of running the IFM. Once the IFM determined the final Schedule at the nodal level, the CAISO would re-aggregate nodal Demand Schedules to the LAP level for the purpose of providing these Self-Schedules to the SCs and for settlement. In the case of Self-Scheduled Demand, the distribution procedure would simply allocate LDF-scaled quantities of Self-Scheduled Demand to each node within the LAP. In the case of Demand Bids, however, the proposed distribution procedure would place a Demand curve at each node, creating prices that were identical to the submitted Bid prices and quantities that were scaled by the LDFs. In the optimization, the determination of LMPs would result in the Demand Bids at each node clearing at different points on each nodal demand curve.

The LECG assessment of the MRTU design identified a serious problem with this approach for distributing Demand Bids to individual nodes and then re-aggregating the nodal Demand cleared in the IFM back up to the LAP level. In particular, because the same Demand curve would be placed at each node within the LAP, the initial distribution of Demand based on the geographically accurate LDFs would be distorted by the fact that large amounts of Demand would clear at low-price nodes and small amounts would clear at high-price nodes. Once these nodal loads were re-aggregated to the LAP level, the resulting schedule would be infeasible because the Demand actually cleared in the IFM at each node would not match the LDF distribution of the LAP-level Demand quantity. The LECG report provides detailed examples of the problems this would cause.

In its May 13, 2005 filing the CAISO proposed a solution to this problem, which is to clear LAP-level Demand Bids based on LAP prices. That is, the LAP-level demand curve would not be distributed to nodes for clearing in the IFM, but would be cleared against the aggregated LAP prices to produce a final LAP-level Demand Schedule that is consistent with the accurate LDFs. This approach is used in the NYISO markets and has been working effectively there.

Q. Are there any risks associated with the LAP Demand-clearing approach the CAISO has adopted?

A. Yes, there is one known risk that should be mentioned, which is related to the IFM only; it does not occur in Real-Time for reasons that will become clear in the discussion below. As noted above, one principle behind the proposed LAP Demand-clearing mechanism is that the LDFs used to distribute the submitted LAP Demand Bids and Self-Schedules to nodes should be preserved in the clearing of Demand against Supply for the LAP. This is an intentional feature because it means that the nodal LMPs and cleared nodal quantities will aggregate to a LAP price and quantity that is on the LAP Demand curve. Moreover, it is this feature that addresses the number one issue that LECG identified in their February 2005 report. This same feature has a potential to lead to undesirable consequences under certain hopefully rare conditions, however. The potential problem and illustrative examples are discussed in the testimony of Dr. Farrokh Rahimi, so I will provide only a sketch of the conditions and the potential outcomes. Essentially, if there is internal congestion within the LAP that creates a load pocket and there is a shortage of supply bids in the load pocket, constraining the LDFs to remain fixed so that LAP Demand clears at a point on the LAP Demand curve can result in either (a) a large volume of LAP Demand being curtailed in the IFM, which shifts that Demand out of the IFM and into Real-Time and leads to a higher level of RUC procurement, or (b) extremely high Day-Ahead LMPs within the load pocket, or (c) both.

Q. What can be done to mitigate the risks of these adverse outcomes?

A. The best mitigating factor is an effective Resource Adequacy program with well-specified local capacity obligations on LSEs, as are being developed this year in proceedings at the California Public Utilities Commission, combined with clear, effective obligations on Resource Adequacy capacity to make itself available to the CAISO. Such obligations would ensure that local supply bid insufficiency – a key condition for the above scenario to occur – would be uncommon, limited to situations where facility outages or derates severely constrain the supply into a load pocket. Even if the CAISO did not use LAPs in the MRTU design, high LMPs in a load pocket can occur when supply into that area is severely constrained. All LMP markets have effective local market power mitigation to minimize the impacts of such conditions on Demand. Another point to keep in mind is that even though local prices in the load pocket may be high, the Demand is settled at a LAP price which corresponds to a point on the LAP Demand curve and thus is a price that Demand is willing to pay based on its submitted LAP Demand Bids.

The other consequence of a local-scarcity condition – the potential for severe curtailment of LAP Demand in the IFM – is a direct consequence of holding the LDFs fixed in all circumstances. From the perspective of economic consistency this is the correct thing to do because, as I said above, it ensures that the cleared nodal Demand and LMPs aggregate up to a point on the LAP Demand curve. But in practical terms these LDFs are statistically derived and as such may deviate from the true distribution of Demand based on their statistical variance. With a sound methodology for estimating the LDFs, the LDFs will be reliable and the random deviations should be small, but even so it is a very strong presumption to insist that the LDFs should be fixed under all circumstances. Moreover, while one could argue that high LMPs in local areas are an appropriate outcome when those local areas are constrained and supply is scarce, it is unrealistic to argue that Demand should be curtailed across an entire LAP when a local constraint is binding. Such curtailment is purely an artifact of the fixed LDFs, which is why I said earlier that this is an IFM problem, not a Real-Time problem. In Real-Time the Demand varies nodally, and its distribution is computed in real-time by the State Estimator, so a local constraint would not force Demand to be curtailed pro rata across the LAP. It would therefore be fully appropriate under the severe local scarcity circumstances discussed here, for the CAISO to take the steps stated in the Tariff, such as slightly increasing an internal constraint, to prevent what would otherwise be a highly artificial – and potentially costly – outcome.

In conclusion, I would say that addressing the problem LECG identified was without question a necessary modification to the CAISO's original approach for clearing LAP Demand Bids. Although I have not said much about that problem, LECG provides a full, illustrated discussion of it in the February 2005 report. And while it is true that fixing the one problem has created the risk of another, and this other should not be taken lightly, it is also true that this newly identified problem can be minimized through effective Resource Adequacy, and is amenable to an effective and reasonable remedy when necessary.

Q. Has the Commission reviewed the CAISO's proposed solution to this problem identified by LECG?

A. Yes, the Commission did so in the July 1, 2005 Order, and therein approved the CAISO's proposal, stating that "We agree that the new proposal avoids several important problems of the original proposal, including avoiding infeasible day-ahead schedules." July 1, 2005 Order at P 34.

C. The Day-Ahead Integrated Forward Market

Q. Please describe, generally, the various components of the Day-Ahead Market and how they operate.

A. The group of market processes collectively referred to as the Day-Ahead Market consists of three major components which are executed in sequence and all utilize the SCUC optimization discussed earlier. The first is the Market Power Mitigation and Reliability Requirements Determination process ("MPM-RRD"), also referred to in some MRTU documents as the "Pre-IFM" process.

The second component is the Integrated Forward Market ("IFM"). It is called "integrated" because it performs simultaneous clearing of an energy pool market along with Congestion Management and the designation of capacity to provide AS, and also performs Bid-based unit commitment. The IFM results in Day-Ahead Energy Schedules for Demand and Supply resources, as well as AS capacity awards, unit commitment instructions for units that were committed by the CAISO, plus the nodal LMPs for settling energy schedules and CRRs, plus the prices for settling AS capacity awards. Greater detail on these functions of the IFM are discussed in the testimony of Dr. Farrokh Rahimi.

The third major component of the Day-Ahead Market is the Residual Unit Commitment or "RUC" process, which is the tool by which the CAISO can designate capacity that was not scheduled in the IFM but is expected to be needed the next day for Real-Time operations to meet the CAISO's Demand Forecast. A tool such as RUC is necessary because the IFM, clearing as it does based on submitted Demand Bids and Self-Schedules, may result in a total level of Demand

and Supply that is significantly short of the forecast for the next day. RUC enables the CAISO to commit additional long-start-up-time units and preserve unloaded capacity to meet expected Real-Time operating needs. Also, the RUC mechanism is consistent with the practices of other ISOs that operate Bid-based Day-Ahead Energy markets, which all have a tool equivalent to RUC, for exactly the same purpose.

Having identified the three major components of the Day-Ahead Market, there are several important details I will describe next. The MPM-RRD or Pre-IFM process of the Day-Ahead Market actually consists of two "passes" or runs of the SCUC whereby the need for local market power mitigation and RMR resources for local reliability are determined and Bids are mitigated appropriately. These must be performed ahead of the actual running of the IFM so that when it runs, the CAISO can be confident that the possible exercise of local market power has been prevented and that RMR units are used for local needs in a manner consistent with their contracts. Details on how the Pre-IFM passes one and two work are provided in the testimony of Dr. Keith Casey.

In summary, the Day-Ahead Market is structured as follows:

Pass 1: First pre-IFM pass, in which only certain pre-specified "competitive" transmission constraints are enforced, as a way to establish a baseline unit commitment and energy Dispatch against which the need for RMR and the opportunities to exercise local market power can be assessed. This pass is called the "Competitive Constraints Run" or "CCR."

Pass 2: Second pre-IFM pass, in which all transmission constraints in the FNM are enforced. Comparison of the results of passes one and two provides the criteria for identifying local generation needs where RMR generation is needed and where local market power opportunities exist that require mitigation of submitted Bids. This pass is called the "All Constraints Run" or "ACR." Together passes 1 and 2 comprise the MPM-RRD process.

Pass 3: The IFM itself, which results in Energy Day-Ahead Schedules, AS awards, unit commitment instructions, and the LMPs and AS prices used in the Day-Ahead settlement process.

Pass 4: The RUC procedure, in which additional capacity is identified and units may be committed, as necessary, to ensure that sufficient generating capacity is on-line in the next operating day to meet the CAISO Forecast of CAISO Demand.

Q. How do the inputs and outputs of the MRTU Day-Ahead Market differ from the current CAISO market structure?

A. Two of the biggest differences between the existing CAISO market design and the MRTU design are first, the integration of a Day-Ahead Energy market with Congestion Management under MRTU, and second, the elimination of the balanced schedule requirement for each SC and the associated market separation rule. Thus, whereas under the CAISO's current market design SCs submit incremental and decremental "adjustment bids" that are used only for Congestion Management, under MRTU they will submit Energy Bids that are used both to clear congestion and to balance Energy supply and demand. Under MRTU each SC will not be required to submit a balanced Schedule in which total Supply equals Demand, but may bid only to buy Energy to serve Demand, or only to sell Energy from its supply resources, or to buy and sell in different and unrelated quantities. As a result of the IFM, each SC receives a Day-Ahead Schedule for its accepted Supply and Demand Bids, and in almost all hours will be either a net seller (with total quantity of scheduled supply greater than total quantity of scheduled demand) or a net buyer (total quantity of demand greater than supply).

Q. Please describe in some more detail the process by which Bids are submitted by SCs and prepared for use in the Day-Ahead Market processes.

A. I will describe this only at a conceptual level because many of the details of the validation processes will be contained in Business Practice Manuals to be developed over the next few months. The process and criteria for validating Bids and for modifying submitted Bids where appropriate are essentially the same for both the DAM, the HASP, and RTM. Just to be clear about terminology used in the Tariff, the generic unmodified term "Bid" refers to the entire submission of an SC to the DAM, the HASP, and the RTM processes, and includes Economic Bids (price-quantity bids) for Energy, AS and RUC capacity, as well as Energy Self-Schedules and AS Self-Provision. Once the Bids are submitted, the software performs a sequence of validation steps to verify the Bid's adherence to the rules about Bid structure, compliance with applicable bidding activity rules, consistency of a resource's Bid with parameters registered in the resource's

Master File, and inclusion of all bid components that may be required of a resource, for example to fulfill its obligations as a RA Resource. For all but the last criterion, Bids found to be invalid prior to the close of the relevant market will be referred back to the submitting SC for correction and resubmission. For Bids that omit or incompletely specify required components the software will construct a modified Bid that is fully complete. The SC submitting such a Bid is informed about these actions and will be able to modify or withdraw such a Bid if CAISO's adjustments take place prior to market close, but once the market closes the SC has no further ability to modify or withdraw a Bid and the constructed Bid will stand. Once the Bid has gone through the validation process and is suitable for inclusion in the market processes it is referred to as a "Clean Bid."

Q. What is the role of Inter-SC Trades in the LMP markets?

A. In the new LMP markets, Inter-SC Trades ("IST") are essentially a convenient settlement feature that enables the parties to a bilateral transaction to allocate certain CAISO costs or charges between them via the CAISO settlement system, rather than having to perform this allocation through an external transaction. An IST must be submitted to the market – either the DAM or the HASP – by both parties, and the submission of both parties must match, that is, must specify the same Trading Hour, grid location, specific commodity and quantity being traded, and must identify one party as delivering and the other as receiving. Given such a match between the two parties' submissions the IST will always net to zero so there is no physical aspect that the SCUC or SCED must take account of, it is purely a financial transaction to be processed in settlements. There is a special type of IST called a "Physical IST," but even this type is still just a settlement feature and does not have any impact on the running of the market SCUC and SCED processes.

Q. What are the types of ISTs?

A. ISTs may be for Energy, Ancillary Services, or IFM Uplift Load Obligation. ISTs may take place at aggregated pricing nodes – the LAPs and Trading Hubs – and at Generating Unit PNodes. All ISTs at Generating Unit PNodes must be Physical ISTs.

Q. Please explain the Physical IST.

A. The Physical IST is an IST of Energy that occurs at a PNode corresponding to a physical Generating Unit. The CAISO will validate that the Energy was indeed scheduled from the designated Generating Unit, in either a Day-Ahead Schedule or an HASP Advisory Schedule, and that the Energy schedule is linked to the IST, either directly if the Generating Unit is actually scheduled by the delivering party to the IST, or indirectly through additional ISTs between the delivering party to the IST and the SC for the Generating Unit. If the amount of Energy scheduled is at least as great as the MWh amount of the IST, then the CAISO settlement system will process the IST based on the price at that location. Alternatively, if the MWh amount of the IST exceeds the amount of Energy that was actually scheduled at the location, the MWh difference will be settled at the price of the

Existing Zone Generation Trading Hub that contains the designated Generating Unit.

Q. How does the IFM simultaneously optimize Energy, Congestion Management, and Ancillary Services awards?

A. I have already discussed the simultaneous optimization of Energy and management of Congestion. A third function that is "integrated" in the IFM is the designation of capacity to provide AS. In today's Day-Ahead Market, AS procurement is performed following Congestion management, using AS capacity Bids that are submitted specifically for that purpose. Under MRTU the SCs will continue to submit AS capacity Bids in the Day-Ahead Market, but under MRTU, unlike the CAISO's current market design, the IFM will consider AS capacity Bids in conjunction with Energy Bids and will make AS awards based on a simultaneous optimization that minimizes the total bid cost of clearing Congestion, balancing Energy supply and demand, and reserving unloaded capacity to provide AS. Under MRTU, the CAISO will continue to procure the following Ancillary Services: Spinning Reserves, Non-Spinning Reserves, Regulation Up and Regulation Down. For the reasons discussed in detail in the testimony of Dr. Rahimi, the CAISO does not propose to continue procuring Replacement Reserve under MRTU. Also, in a manner similar to the CAISO's existing market design, the MRTU optimization process will be able to substitute higher-quality AS products for lower quality AS products; for example, it may reserve additional Spinning Reserves to cover part or all of the Non-Spinning Reserve requirements.

Perhaps a less obvious, but nevertheless important consequence of the integration of AS with energy and Congestion management in the IFM, is the ability of the IFM to utilize Import transmission capacity in an economically optimal manner to import Energy and AS. Under today's market design, Congestion Management is performed first and establishes Import flow schedules, after which AS can be procured from imports only to the extent that there is Import transmission capacity remaining. Under MRTU, however, the IFM will utilize Import transmission capacity for the most economically efficient combination of Energy and AS.

Q. What provisions does MRTU offer for participants who transact most of their Energy needs through bilateral contracts and do not wish to buy or sell Energy through the IFM, except perhaps for small balancing quantities?

A. The most important provision under MRTU with respect to scheduling bilateral transactions is the provision allowing for SCs to "Self-Schedule" Supply and Demand. In order to Self-Schedule Supply or Demand, the SC will submit a Schedule containing a quantity of Demand, or a quantity of Supply from a specific generator or Scheduling Point, without any associated economic Bids. When the IFM sees such Self-Schedules, it will first attempt to perform the optimization utilizing only the Economic Bids without modifying the Self-Schedules in any way. If this is successful – that is, if Energy Supply and Demand can be balanced, all Congestion resolved, and the targeted quantities of AS awarded – then all Self-Schedules will be accepted without modification. For settlement purposes they will be treated as price-takers in the market, because by their choice not to submit economic Bids these SCs have indicated their willingness to accept whatever prices are produced by the IFM in order to have their Schedules accepted.

Q. Have any parties raised concerns with respect to the manner in which the CAISO proposes to treat bilateral contracts under MRTU?

A. Yes. First, during the MRTU development process, some parties have inquired as to why, if the Energy behind a Self-Schedule has been transacted through a bilateral contract or perhaps is provided by a generator owned by the load-serving entity, there is any need for the Self-Schedule to go through the CAISO settlement process at all. The answer to this is that the IFM settlement process is not just for purposes of ensuring that there is sufficient Energy to serve Demand in the CAISO Control Area, but also to account and charge for Congestion and transmission losses. Thus, a balanced bilateral arrangement, where say 100 MWh of supply are injected at Node A in a given hour to serve Demand scheduled at a Default LAP will have an IFM settlement for 100 MWh times the price differential between the Default LAP and Node A. The Energy portion of this settlement will equal zero because the Energy component of the LMPs is the same at all nodes and therefore drops out of the equation. The non-zero part of the settlement will, therefore, represent the costs of Congestion and losses, and must be settled because these costs reflect the use of the CAISO grid by the contracting parties. Failure to do so would mean that these costs would be passed on to entities that were not a party to these transactions, resulting in a settlement methodology that is inconsistent with the principles of cost-causation.

Second, some parties have raised concerns about the financial impacts of settling the full amount of a bilateral arrangement through the CAISO settlement process when the Energy has been transacted at a contractual price outside the CAISO markets. Revisiting the 100 MWh example above, clearing this transaction through the CAISO settlement process means that the 100 MWh of supply will be paid the LMP at Node A and the 100 MWh of Demand will be charged the IOU-LAP price. One major concern expressed is that this balanced bilateral arrangement will be deemed a purchase and sale through the CAISO markets and, on that basis, used in the calculation of each party's credit posting requirements and their proportional shares of any settlement shortfall due to a payment default by another party. The CAISO's MRTU proposal addresses this concern by specifying, first, that credit posting requirements are based on each party's net obligations to the CAISO. Thus, the 100 MWh bilateral transaction would represent an obligation to the CAISO only with respect to costs of Congestion and losses associated with scheduling the transaction. Second, exposure to settlement shortfalls due to another party's payment default is based on the net amount owed by the CAISO to each party for the relevant settlement interval. Thus, for the 100 MWh transaction noted above, the SC would be exposed to a potential payment shortfall only if the LMP at Node A were greater than the IOU-LAP (Default LAP) price, so that the transaction resulted in a net amount due from the CAISO to the SC, and in that case, the exposure would be proportional to that net amount due.

A third major concern raised about flowing scheduled bilateral transactions through the CAISO settlement process, has arisen with respect to situations when the Supply and Demand are scheduled by two different SCs. Continuing the same example as above, suppose SC1 schedules the 100 MWh of Demand and is charged $6000 for this Schedule (100 MWh times a Default LAP price of, say, $60 per MWh), while SC2 schedules the 100 MWh of generation and is paid $4000 for this schedule (100 MWh times a Node A LMP of, say, $40 per MWh). The difference between these prices ($2000 or $20 per MWh) is appropriately collected by the CAISO to cover the costs of Congestion and losses. But suppose also that under a bilateral contract SC1 (or the LSE represented by SC1) pays $55 per MWh to SC2 (or to the supplier represented by SC2) for the 100 MWh of delivered energy. If no other payment flows between these parties for this transaction, the buyer has paid twice for the energy (once under the contract and once to the CAISO, for a total of $115 per MWh) and the seller has been paid twice (once under the contract and once from the CAISO, for a total of $95).

There are two reliable and straightforward ways to rectify this situation, one that is outside the CAISO settlement process and purely between the contracting parties, and another that utilizes the CAISO settlement process. The first way is for the parties to agree to view their contract as a "contract for difference" or "CFD" that is defined relative to a pre-specified pricing location for which IFM prices are posted by the CAISO. The parties could choose the generator location (Node A) to define their CFD, or the Demand location (the Default LAP), or any other location, single node or aggregation of nodes, for which prices are posted by the CAISO or could be calculated from prices posted by the CAISO. (Of course, the parties don't have to use IFM prices at all for their CFD, since the CFD is completely outside of the CAISO Markets and systems, but using IFM prices would be a relatively simple and transparent approach for them to adopt). Suppose, for example, that the parties agree to use the NP15 Trading Hub to define their CFD. Then, in addition to the payments described in the previous paragraph, the seller agrees to pay the buyer the NP15 Hub price for each of the 100 MWh. In so doing, the seller agrees to pay the costs of Congestion and losses for moving power from Node A to the NP15 Hub, and the buyer agrees to pay the costs of Congestion and losses for moving power from the NP15 Hub to the Demand at the Default LAP. The total of the Congestion and losses paid by both parties will total $20 per MWh in the example we have been discussing.

To illustrate, suppose the NP15 Hub price is $50. After paying $50 per MWh to the buyer, the seller nets $45 per MWh, which is the $55 bilateral contract price minus the $10 cost of Congestion and losses for going from Node A to the NP15 Hub ($50 - $40 per MWh). The buyer's net cost is $65 per MWh, which is the $55 bilateral contract price plus the $10 cost of Congestion and losses for going from the NP15 Hub to the Default LAP ($60 - $50). Thus, the end result is that the two parties have transacted at the agreed upon contract price of $55, and have also divided the total $20 per MWh cost of Congestion and losses based on a financial "hand-off" of the power at the NP15 Hub.

The other way these parties may rectify the double payment problem is through the CAISO settlement process, using the Inter-Scheduling Coordinator Trade ("IST") mechanism. This mechanism allows two trading parties each to submit one side of an IST for a specific MWh quantity, trading hour and grid location, the result of which is that the CAISO settlement system will effect a charge to the seller and a payment to the buyer equal to the specified locational price, times the MWh quantity. In the example above, if the two parties were to submit an IST at the NP15 Hub, the financial impact to the two parties is exactly the same as they would be under the method that avoids the CAISO settlement system. Under the MRTU rules, parties may submit ISTs only at designated "Existing Generation" or "EZGen" Trading Hubs – that is, trading hubs that coincide with today's NP15, SP15 and ZP26 Congestion Zones – or at Default LAPs or MSS-LAPs. In addition, if they utilize the "Physical IST" mechanism whereby the physical power injection behind the trade is validated by the CAISO, the parties may submit an IST at the grid location corresponding to the validated power injection. Of course, if parties choose to implement their CFD outside the CAISO settlement they can use any locational price as the basis for defining their CFD.

The important point to derive from the lengthy example discussed above is that the CFD, whether or not it is implemented through the CAISO settlement system, is an effective way to correct the double payment that results from the combination of settling a bilateral Energy contract outside the CAISO and settling with the CAISO for the scheduled energy injection and withdrawal, when two different parties are scheduling the injection and the withdrawal. The parties cannot avoid paying for the Congestion and losses associated with the Schedule, because these are the costs of using the CAISO grid, but the choice of the location at which to implement their CFD settlement (using the IST mechanism if they wish) is the means to determine how the Congestion and losses charges will be divided between the seller and the buyer.

Q. Can the IFM results be characterized as binding commitment and Dispatch Instructions by the CAISO?

A. The results of the IFM (*i.e*. Pass 3 of the Day-Ahead Market sequence as described above) are financially binding on all parties; that is, SCs will be paid and charged the prices that result from the IFM for the scheduled quantities of Energy and the awarded quantities of AS capacity. In addition, the CAISO will ensure recovery of Start-Up and Minimum Load costs for units committed by the IFM economic unit commitment, in accordance with details described more fully in the testimony of Dr. Farrokh Rahimi. Any departures from the IFM Energy Schedules, or any failures to provide the AS capacity awarded in the IFM, will be subject to further financial settlement adjustment based on prices calculated in the Real-Time Market process, including the Hour-Ahead Scheduling Process ("HASP"). In this sense the IFM results represent performance commitments as well as financial commitments, because subsequent deviations from the performance specified in the IFM results will be subject to further settlement impacts.

Q. To what extent does the IFM procure Ancillary Services in the Day-Ahead timeframe versus deferring some Ancillary Services procurement for subsequent markets?

A. Under MRTU the Day-Ahead procurement requirements for AS – specifically operating reserves and regulation – will equal 100 percent of the CAISO's forecasted Real-Time requirements. As a result the CAISO will need to procure additional AS in the HASP/RT process only as a result of an increased requirement beyond the Day-Ahead forecast or the unavailability of some of the capacity that was procured Day-Ahead. Thus the additional post-Day-Ahead requirements are expected to be small in general. The CAISO will meet such additional requirements by procuring AS from imports in the HASP and from internal generation in the Real-Time Pre-dispatch process ("RTUC") that is part of the Real-Time Market. I will discuss the elements of the Real-Time market a little later in this testimony. Also, this topic is addressed in considerable detail in the testimony of Dr. Farrokh Rahimi.

Q. Have parties raised any questions concerning the CAISO's MRTU AS procurement strategy?

A. Yes. One question that has been asked regarding the 100 percent Day-Ahead target is whether the CAISO feels confident that it can meet this target regularly without excessively driving up AS prices. The CAISO does believe that it can do so, because there are complementary provisions in the design of the IFM and in the Must-Offer Obligations that apply to Resource Adequacy capacity ("RA-MOO") to ensure that sufficient AS can be procured in the IFM to meet the 100 percent requirement in all but the most severe system shortage conditions. First, the RA-MOO stipulates that RA capacity from resources that Bid Energy into the Day-Ahead Market can be optimally scheduled for Energy or awarded AS, even if the resource does not explicitly submit capacity Bids for AS. If it does not submit capacity Bids, it will be optimized using proxy capacity Bids at $0 per MW, up to the quantity of capacity that can meet the performance requirements for each AS. This means that the IFM should have a considerable pool of potential AS capacity in all hours except under extreme circumstances. Second, the IFM optimization is configured to assign greater priority to the award of AS than to scheduling Energy, up to 100 percent of the CAISO's daily AS procurement target. Therefore, if there is not enough Supply Bid into Day-Ahead Market to clear both Energy Demand and meet the AS requirement, the IFM will procure the AS first and schedule less Demand if necessary.

Q. Can Ancillary Services be self-provided under MRTU?

A. Yes. As with the CAISO's current market design, SCs will, under MRTU, be able to designate specific capacity as self-provided AS in the IFM. SCs will also be able to designate self-provided AS in the HASP/Real-Time Market, but if they desire a high confidence that their self-provided AS will be accepted by the

CAISO, they should submit it in the IFM, because in the subsequent markets, the CAISO will accept self-provided AS only as such additional capacity needed to meet post-Day-Ahead AS requirements, which as I noted earlier are expected to be small in most hours.

Q. Please describe procurement of Ancillary Services using Ancillary Services Regions under MRTU.

A. Under MRTU, the IFM will be configured to procure AS on a locational basis, by satisfying constraints that specify minimum quantities to be procured within each of several designated sub-areas of the grid referred to as "AS Regions." Initially, the CAISO will not specify AS Regions any more granular than the present Congestion zones, in order to be sure that local market power in the AS markets is not a problem. For Release 2, however, the CAISO will consider whether more granular AS Regions are needed from an operational perspective and if so, what provisions are needed to ensure that such regions can be created so that any resulting local market power is effectively mitigated in the AS markets. The issue of AS Regions is discussed in detail in the testimony of Dr. Farrokh Rahimi.

D. Residual Unit Commitment

Q. Please describe the Residual Unit Commitment process in the Day-Ahead Market.

A. Under MRTU, the IFM will clear the market based on the Self-Scheduled and Bid-in Demand of the SCs, and as a result it may clear at an overall level that is significantly lower than the CAISO's Demand Forecast for the next day. The purpose of the RUC process is to assess the resulting gap between the Day-Ahead procurement and the CAISO's Demand Forecast, and to ensure that sufficient capacity is committed, on-line and available for Dispatch in Real-Time in order to meet the Demand Forecast for each hour of the next day. To achieve this objective, the RUC process may commit and issue Start-Up instructions to resources that were not committed at all in the IFM, as well as identify additional unloaded capacity from resources that were committed and scheduled in the IFM and designate this capacity as needed for Real-Time Dispatch in particular hours of the next day.

To perform this function, the RUC utilizes the same SCUC optimization and FNM that the IFM used, but instead of using Bid-in Demand, it will distribute the CAISO Demand Forecast over the nodes of the FNM using the same load distribution factors (LDFs) that will be used to distribute LAP Demand in the IFM. It will then treat all IFM resource (generation and Import) Schedules and Export Schedules as fixed, and therefore not to be re-optimized, include any Supply resources that were offered into the Day-Ahead Market but may not have been scheduled in the IFM, and determine a new optimal Unit Commitment and Dispatch to meet the Demand Forecast at each node. In performing this optimization RUC ignores submitted Energy Bids and uses RUC availability Bids instead, with the restriction that such Bids must be zero for all capacity that has been designated Resource Adequacy capacity. RUC also considers Start-Up and Minimum Load costs for units that were not committed in the IFM. Based on these Bids the RUC process calculates, in addition to the new unit commitment and Dispatch process, RUC prices at each FNM node. The RUC process thus designates RUC capacity on a locational basis, in the sense that it identifies such capacity by determining a feasible Dispatch of that capacity to meet the CAISO's Demand Forecast.

Q. Please explain how the capacity scheduled through RUC is compensated.

A. As a result of the RUC optimization, the capacity scheduled to meet the Demand Forecast that was not scheduled in the IFM is designated "RUC Capacity" and may or may not be eligible to be paid the nodal RUC price. For instance, RA Capacity and RMR capacity that the MPM-RRD process has determined to be needed for local reliability are not eligible to receive the RUC price payment if they are designated as RUC Capacity, but non-RA, non-RMR capacity is eligible in most cases. The capacity eligible to receive the RUC availability payment is called the "RUC Award" in the MRTU Tariff. In addition to the RUC availability payment, resources committed by RUC that were not committed in the IFM are guaranteed their Start-Up and Minimum Load Costs just as if they were committed by the IFM, and this applies to both RA and non-RA resources.

Q. Will the CAISO procure AS through RUC?

A. No. As I stated earlier, the CAISO will seek to procure 100 percent of its forecast AS requirements in the IFM, and will place a higher priority in the IFM on procuring the needed AS over scheduling capacity to provide Energy. Moreover, system conditions including the Demand Forecast do not change between the IFM and RUC, as both procedures are simply "passes" in the Day-Ahead Market process, the totality of which occurs between 10 AM and 1 PM of the day ahead of each operating day. The RUC procedure therefore has no provision for procuring additional capacity for AS.

Q. How will the CAISO determine its RUC procurement needs?

A. Generally speaking, the RUC procurement target will be based on the difference between the CAISO's Demand Forecast for each hour of the next operating day and the hourly IFM Energy Schedule for that day. This is not a complete explanation of the process, however, because the CAISO will need to make some adjustments to this baseline quantity to minimize the potential for systematic over- or under-procurement. For example, some supply capacity becomes available only during the operating day, or may be procured through bilateral deals that take place after the close of the Day-Ahead Market, and this capacity will be offered or Self-Scheduled in the HASP/Real-Time process. If the CAISO were to completely overlook what will be a regular and reasonably predictable occurrence, it would risk systematically over-procuring RUC capacity on a regular basis. Alternatively, if the CAISO does not allow a margin for Demand Forecast error or over-estimates, the supplies that are expected to appear in the HASP/Real-Time process, the CAISO would risk systematically under-procuring RUC capacity and be short in Real-Time. To take another example, intermittent resources that participate in the Participating Intermitted Resources Program

("PIRP") may be designated RA capacity in fulfillment of a load-serving entity's RA requirement. But unlike other RA capacity, PIRP capacity is not required to participate in the Day-Ahead Market because Day-Ahead Demand Forecasts are not deemed by grid operators to be sufficiently reliable at this time. And yet, if the RUC were to totally ignore the Real-Time output of PIRP resources, it would risk systematically over-procuring RUC capacity.

Given these realities, the CAISO has identified the development of a robust approach to developing a RUC procurement methodology that will minimize systematic over- and under-procurement of RUC capacity. The CAISO has identified this as a high-priority activity to begin later this year with the participation of stakeholders, with the ultimate goal that this methodology will be included in one of the CAISO's Business Practice Manuals.

Q. Will the CAISO favor either the over-procurement or under-procurement of RUC capacity over the other?

A. It should be understood that "over-procurement" is not a definitive concept when applied to RUC. RUC capacity is somewhat like insurance, just because one does not ever need to file an insurance claim doesn't mean that buying insurance is a waste of money. In general, the consequences of not having insurance when one needs it tend to be worse than the financial consequences of paying to have insurance and not needing it. Similarly, in the context of RUC, the consequences of under-procurement can be supply shortages, staged emergencies, operating violations, and even involuntary curtailment of Demand. These – especially

Demand curtailment – can be costly, and therefore the CAISO expects, and acts pursuant to the belief that consumers and state policy makers would prefer that the CAISO procure sufficient RUC capacity to avoid such costly consequences, rather than attempting to drive RUC procurement costs to zero at the risk of a supply shortfall. The CAISO therefore expects the RUC target-setting methodology to evolve over time and stabilize at a reasonable cost as the CAISO gains more experience operating under the MRTU markets. Nevertheless, parties should not expect that the CAISO will ever reach a point where, on average, there is zero or close to zero RUC capacity procured that is not utilized in Real-Time. That would be an imprudent and unrealistic goal.

Q. How does the RUC process relate to the Must-Offer Obligations for Resource Adequacy capacity ("RA-MOO")?

A. Under the RA-MOO provisions, RA capacity that is not scheduled in the IFM is required to participate in RUC with a $0 RUC Bid, and will not be paid a RUC availability payment even if a positive RUC price at its node is set by the RUC optimization. Non-RA capacity that participates in the IFM has the option to participate or not in RUC. Non-RA capacity cannot, however, bypass the IFM and participate only in RUC; it must have participated in the IFM and not been scheduled in order be included in the RUC. If it participates in RUC it may submit a single-step RUC Bid – that is, one Bid price for all offered non-RA capacity – at any value up to the Energy Bid cap, which will be $500 per MW when MRTU is implemented. In addition, one of the new provisions worked out with stakeholders in the 2005 MRTU stakeholder process is the ability of a resource to have both RA and non-RA capacity (*i.e.* be a "partial RA resource"). Such resources must submit $0 RUC Bids for any RA capacity not scheduled in the IFM for either Energy or AS, and may submit a positive RUC Bid for their non-RA capacity.

Q. To whom will costs of capacity committed in RUC be allocated and on what basis?

A. The RUC cost allocation is two tiered to reflect the two types of criteria driving the RUC procurement target. First, the total costs of the RUC procurement on an hourly basis are divided by the MW quantity of RUC capacity procured for the hour, and charged MW-for-MW to Real-Time Demand – including internal Demand and exports – that was not scheduled in the IFM. This is appropriate as a methodology for first tier cost allocation because the quantity of RUC procurement is driven primarily by the shortfall between the IFM Schedule and the Demand Forecast. Because RUC procurement targets are established based on Demand Forecasts, however, there is the possibility that more MW of RUC could be procured than MW of unscheduled Real-Time Demand. In this case, the unscheduled Real-Time Demand will still pay the per-MW cost of the RUC capacity needed to meet the actual Real-Time Demand, but the cost of the remaining RUC capacity will be spread to all Real-Time metered Demand as part of the neutrality account. This is appropriate as a second tier cost allocation methodology because RUC procurement is similar to an insurance policy, as discussed above, which means that sometimes there will be more RUC procured than needed to cover the actual gap between the IFM and the Demand Forecast, and this insurance benefits all consumers who depend on the reliability of the grid.

E. <u>The Hour Ahead Scheduling Process</u>

Q. Please describe how the CAISO's proposed Hour Ahead Scheduling Process ("HASP") fits in with the larger MRTU market structure.

A. Under MRTU, the HASP is basically an extension of the Real-Time Market. There will be one submission of Bids for the entire set of Real-Time Market processes, which include the MPM-RRD procedures, the HASP, the RTUC, the Real-Time Dispatch ("RTD"), and the Short Term Unit Commitment ("STUC"). I will discuss the RTUC, RTD and STUC concepts in more detail later in this testimony, in the section devoted specifically to the Real-Time Market, but for now it is important to understand that the HASP is part of a special, hourly run of the RTUC, which otherwise runs every 15 minutes to perform certain tasks to provide needed inputs to the RTD. The non-HASP aspects of the RTUC are discussed in the section discussing the Real-Time Market.

The Bid submission for the Real-Time Market processes opens as soon as the results of the Day-Ahead Market for that trading day are published, and closes at 75 minutes prior to each operating hour (T-75). The special hourly RTUC that includes the HASP then runs at (T-67.5) and performs a complete optimization utilizing essentially the same SCUC algorithm as in the IFM, except that instead of optimizing over 24 intervals of one hour each as the IFM does, this RTUC run optimizes over seven intervals of 15 minutes each to cover the period from (T-45) to (T+60). The four 15-minute intervals comprising the hour from (T-0) to (T+60) are referred to as the "pre-dispatch hour" and comprise the actual target of the HASP function of this special RTUC run. The Bids that were submitted at (T-75) apply only to this pre-dispatch hour, whereas the optimization for the three intervals from (T-45) to (T-0) utilizes the Bids that were submitted an hour earlier, that is at (T-135) relative to the time line we are discussing here. In other words, the HASP run of the RTUC actually optimizes over seven 15-minute intervals, but the features that are unique to the HASP run refer only to the last four of these intervals, which comprise the pre-dispatch hour. In this section, I will describe the HASP function in more detail, and return to the other aspects of the RTUC when I discuss the Real-Time Market.

Q. Please describe how the HASP optimization works and what its results are used for.

A. The HASP starts with two preliminary passes that are equivalent to Passes 1 and 2 of the Day-Ahead Market, referred to as the MPM-RRD passes. These passes perform market power mitigation and reliability or RMR Dispatch for the pre-dispatch hour. The mitigated Bids are used in all further optimization runs for this trading hour, including the HASP optimization itself, and the subsequent RTUC runs, the STUC and also the five-minute RTD once the actual operating hour arrives. The details of the HASP local market power mitigation and reliability Dispatch are covered in the testimony of Keith Casey.

Next, the actual HASP optimization is performed, which is analogous to Pass 3 of the Day-Ahead Market, the difference being that in the case of HASP the CAISO Demand Forecast is used for internal Demand instead of Demand Bids and Self-Schedules submitted by SCs as in the IFM. The Demand Forecast is used because the two essential functions of the HASP are the pre-dispatch of Real-Time supplemental energy from interties, which can only be Dispatched on a 60-minute basis, and the procurement of economic imports of AS – which also must be procured on a 60-minute basis – in the event the CAISO identifies the need for additional AS in Real-Time.

The HASP optimization determines an optimal unit commitment and feasible Dispatch for each 15-minute interval of the pre-dispatch hour, determines which capacity from interties and internal generators should be used in each interval to provide any needed AS, and calculates a complete set of prices for each interval. However, the prices calculated in HASP are used to settle only those Schedules and awards that are not subject to subsequent re-optimization by the later RTUC runs and the five-minute RTED. These consist of accepted Import and Export schedules (except for dynamically scheduled resources), as well as any AS procured on the interties. In contrast, the Energy schedules and AS awards determined by HASP for internal generators and dynamically scheduled imports are advisory only; they will be re-optimized in subsequent processes and settled at Real-Time prices.

Q. Why does MRTU feature two different pricing schemes for different types of resources instead of a complete Hour-Ahead settlement market in which all resources can participate, as exists under the CAISO's current market design?

A. When the CAISO filed its comprehensive market design proposal in July 2003 it included a complete Hour-Ahead settlement market, so that the overall market design at that time featured a three-settlement system as exists today. But over the course of the FERC MRTU technical conferences held in 2004, the CAISO began to explore with stakeholders ways to simplify the Hour-Ahead Market design so as to be able to move the Hour-Ahead scheduling deadline closer to the start of the operating hour while still providing the essential functionality that parties wanted from an Hour-Ahead scheduling process. In addition, from a settlements perspective, having only two complete settlements instead of three would reduce ongoing operating costs for all parties. To these ends, the CAISO examined the Balancing Market Evaluation ("BME") that is used in the New York ISO market design, and concluded that a similar approach could meet parties' needs in California, and thus the CAISO began developing the HASP proposal.

Even though the MRTU design with HASP is now a two-settlement market system, there is still a need to use Hour-Ahead prices for certain limited purposes due to the fact that some resources – specifically those that utilize the interties – can be Dispatched only for the full hour, whereas internal resources can respond to five-minute Dispatch instructions. These two types of resources are differently situated and therefore must be treated differently in certain respects.

The CAISO's initial proposal for the simplified Hour-Ahead market, as submitted in May 2004, did not contemplate separate settlement prices for the interties, but proposed to settle all transactions at Real-Time prices. However LECG's comprehensive review of the MRTU design, published in February 2005, identified a problem with using Real-Time prices for settling interties, a problem that the New York ISO had experienced when it first implemented its BME and had resolved by settling interties at Hour-Ahead prices in those instances where the interties are congested in the BME process. The CAISO's May 2005 filing of the HASP proposal adopted this solution. At the same time, the CAISO was still working on another, related intertie settlement problem that arose with the implementation of Phase 1B of MRTU in October 2004. The CAISO had implemented an interim solution to that problem but was still considering what to adopt as a permanent solution that would apply under LMP, , and ultimately concluded that the best approach would be to settle HASP intertie schedules at Hour-Ahead prices in all hours irrespective of any Congestion on the interties. This is the HASP proposal that is embodied in the current tariff filing.

Q. What was the Phase 1B problem that led to the proposal to settle HASP intertie schedules at HASP prices in all hours, rather than just when there is congestion on the interties?

A. The initial MRTU design featured, instead of the HASP, a full Hour Ahead settlement market plus a pre-dispatch process for inter-ties right before each operating hour. In the pre-dispatch, the accepted hourly energy Bids of imports and exports could not set Real-Ttime prices but were guaranteed their Bid price or better. This "Bid or better" settlement rule was retained as a feature of the initial implementation of Phase 1B, and it meant that such resources either received or paid the Real-Time price established by the five-minute Dispatch, plus an uplift when needed to cover their accepted Bid. But once Phase 1B went into operation, this approach resulted in excessive costs and cost shifts, and this led the CAISO to modify the rules and adopt an interim "pay as bid" solution to be used until the LMP markets came into effect.

Q. How did Phase 1B change the CAISO's Real-Time Market so as to cause the existing "Bid or better" settlement rule to become problematic?

A. Phase 1B was a preliminary step in moving towards the comprehensive MRTU design, and as such it provided for economic Dispatch in the pre-dispatch process as well as in each Real-Time Dispatch interval. Under economic Dispatch, all Bids to buy Energy at prices higher than Bids to sell Energy are cleared, even in the absence of any need for Real-Time Imbalance Energy. To do economic Dispatch in the inter-tie pre-dispatch, the software converts the submitted Bids for Energy Exports into a demand curve which it combines with the forecast of imbalance energy needs for the CAISO control area. The pre-dispatch then clears this combined demand curve against the available supply resources including Bids to supply energy from imports, and when there are Bids to buy energy for export at higher prices than Bids to supply energy from imports the economic Dispatch clears these "overlapping" Bids.

This economic clearing of Bids was not done in the CAISO's Real Time Market prior to MRTU Phase 1B, and it was the combination of economic clearing with the Bid-or-better settlement rule that created the problem. For example, suppose that in one hour the pre-dispatch clears a 100 MW import Energy supply Bid at a price of $50/MWh against a 100 MW export Energy demand Bid at a price of $50/MWh. If the real time MCP was only $40, the ISO would pay for 100 MWh of imported Energy its Bid price of $50/MWh, but would collect only $40/MWh for the 100 MWh of exports, thus requiring $1000 to be collected through an uplift charge. Alternatively, if the real time MCP ended up to be $60, the ISO would pay this price to the 100 MWh of imports but would collect only $50/MWh for the 100 MWh of exports, again leaving $1000 to be collected through an uplift charge. Thus, unless the Real-Time price is exactly the same as the price at which Bids were cleared during the pre-dispatch process, the CAISO would incur a net revenue loss associated with the pre-dispatched Bids, resulting in an uplift charge. This was the reason the CAISO filed Amendment 66 and then adopted the FERC-approved interim "pay as Bid" solution to be applied from the time FERC approved Amendment 66 (March 24, 2005) until the start of the LMP markets.

Q. How did the CAISO arrive at the current HASP proposal as the preferred permanent solution to the Phase 1B problem?

A. The CAISO held discussions with stakeholders to evaluate alternative solutions, and ultimately determined that the current proposal is preferred for several reasons. The proposal included in the present filing is to settle hourly pre-dispatches at pre-dispatch prices calculated in the HASP, specifically, the simple average of four 15-minute prices computed by the HASP optimization. The simple average of the four 15-minute pre-dispatch prices will be equal to or higher than the highest accepted hourly import Bid and will be equal to or less than the lowest accepted hourly export Bid.

In the process, the CAISO considered the NYISO approach of settling the pre-dispatches at HASP prices only when there is congestion on the associated intertie, but realized that this approach would not solve the Phase 1B problem. When the intertie is not congested, then the settlement rule would revert to "Bid or better" relative to the Real Time price, and thus the problem of excessive uplift costs due to clearing the overlapping Bids re-emerges. In contrast, the proposed solution eliminates the Phase 1B problem, except possibly under extremely rare conditions. It also ensures Bid Cost Recovery for intertie Bids on a daily basis and, as a single price auction it encourages competitive bidding.

Q. How does the HASP meet parties' needs for an effective Hour-Ahead process?

A. When the CAISO initiated the discussions to simplify the Hour-Ahead market, we asked parties what functions they needed and the parties stated specifically that they needed primarily to: (1) Self-Schedule, ahead of the operating hour, additional supply resources they obtain after the Day-Ahead Market, so they could know whether these resources would be deliverable to meet any additional Demand that was not scheduled in the Day-Ahead Market; and (2) submit such Self-Schedules as close to the operating hour as possible. In addition, the CAISO needs to be able to pre-dispatch supplemental energy that is Bid into the Real-Time Market by intertie suppliers, because these supply resources can only be procured on a 60-minute basis and if not procured at least 45 minutes prior to the operating hour, cannot be accessed at all during the operating hour (except for dynamically scheduled interties, which comprise a very small share of interchange flows today). Combining these needs, the CAISO realized that an effective design approach would be to combine what were originally two separate features of the MRTU design – the Hour-Ahead Market and the Real Time Pre-dispatch – into a single feature that served the essential purposes of both, but eliminated the third settlement process and allowed all parties to schedule new supply resources 45 minutes closer to the start of the operating hour than was possible with a separate HA market, that is, at 75 minutes rather than 120 minutes before the start of the operating hour.

Q. Are there Bids or Self-Schedule changes for Demand in the HASP?

A. The only Demand Bids relevant to the HASP are Export Bids, because these must be scheduled as 60-minute interchange Schedules. From a grid operator's perspective, it is essential to use the CAISO Demand Forecast in HASP, rather than submitted Demand Bids and Self-Schedules, in order to enable the CAISO to pre-dispatch the optimal quantity of supplemental energy from imports. For internal Demand, their settlement will be at RT prices for whatever quantity was not scheduled in the Day-Ahead IFM. The main need expressed by the internal LSEs is to be able to schedule the supply resources they want to utilize to meet their Real-Time Demand so that their Demand is served by their procured supplies rather than through the CAISO Real-Time Market, and the HASP does accommodate this.

Q. Can changes be made to Self-Schedules of Supply in the HASP?

A. Yes. In fact, SCs that wish to maximize the certainty that resources submitted to the Real-Time Market process will actually be feasible to run at the desired level in Real-Time should submit these as Self-Schedules, that is, as nominated MWh quantities without economic Bids. If these supplies are coming over the interties, they will be given binding 60-minute Schedules if accepted, and will be settled at HASP prices. If these supplies are from internal generators and are found in HASP to be feasible, they will be given Schedules that are formally considered advisory, but because they do not have economic Bids associated with their Self-Scheduled quantities they will not be re-optimized in Real-Time except in circumstances where economic Bids are fully exhausted without the RTD obtaining a feasible Dispatch, in which case some HASP Self-Schedules may need to be modified.

F. <u>The Real Time Market</u>

Q. Please provide an overview of the processes that comprise the Real Time Market (RTM).

A. As noted earlier, the RTM can be thought of as a set of processes that includes the MPM-RRD, the HASP, the Real Time Unit Commitment ("RTUC"), the Real Time Economic Dispatch ("RTED"), and the Short Term Unit Commitment ("STUC"). There is one Bid submission that provides Bids to be used in all these processes, and this Bid submission closes at 75 minutes prior to the associated Trading Hour (T-75). I have already discussed the HASP in some detail; now I will discuss the other three major elements of the RTM process. The following discussion assumes that all Bids referred to have been modified as appropriate by the MPM-RRD process for the corresponding Trading Hour. For detailed discussion of the MPM-RRD process please see the testimony of Dr. Keith Casey.

The RTUC runs every 15 minutes, at (T-67.5, which is the HASP run of the RTUC), (T-52.5), (T-37.5), and (T-22.5). The following table summarizes what each of these runs does.

Time of Run	Time Horizon	Functions Performed
(T-67.5)	15' intervals from (T-45) to (T+60)	HASP function for (T-0) to (T+60) RTUC functions for (T-45) to (T-30)
(T-52.2)	15' intervals from (T-30) to (T+60)	RTUC functions for (T-30) to (T-15)
(T-37.5)	15' intervals from (T-15) to (T+60)	RTUC functions for (T-15) to (T-0)
(T-22.5)	15' intervals from (T-0) to (T+60)	RTUC functions for (T-0) to (T+15)
(T-7.5)	15' intervals from (T+15) to (T+120)	HASP function for (T+60) to (T+120) RTUC functions for (T+15) to (T+30)
Etc.	Etc.	Etc.

All of the first four runs utilize the same two sets of Bids, the set submitted at (T-135) for the Trading Hour (T-60) to (T-0), and the set submitted at (T-75) for the Trading Hour (T-0) to (T+60). Then at (T-15) a new set of Bids is received for the Trading Hour (T+60) to (T+120), so the RTUC cycle shifts to a new time horizon as indicated in the fifth run in the table.

The "HASP functions" noted in the table were described above in the HASP discussion. The "RTUC functions" are to perform Real-Time Unit Commitment and procure any AS capacity that may be needed for the 15-minute interval starting 22.5 minutes after the run, as indicated in the table. Referring back to the earlier mention of Real-Time procurement of AS from internal generators on a 15-minute basis, the RTUC is the tool that performs this function.

Whereas the RTUC performs a full unit commitment, the RTD is simply a five-minute economic Dispatch that utilizes the unit commitment and AS designations that resulted from the associated RTUC. For example, the three RTD runs for the Dispatch Intervals beginning at (T+15), (T+20) and (T+25) are executed starting at (T+10), (T+15) and (T+20), respectively, utilizing the unit commitment and AS results of the RTUC that was run at (T-7.5). The RTD does not look myopically at only the next five-minute interval, however; rather it looks ahead for as many as 13 five-minute intervals but issues binding Dispatch Instructions only for the first five-minute interval.

The STUC runs essentially in parallel to the RTUC and RTD. Its function is to make optimal unit commitment determinations over a multi-hour time horizon on a rolling hourly basis. The STUC runs at (T-52.5) and covers seventeen 15-minute intervals from (T-15) to (T+240). Thus, the STUC is able to make optimal unit commitment decisions for resources referred to as "fast-start" and "short-start" in the Tariff.

Q. Please describe how MRTU classifies Generating Units for purposes of Unit Commitment by the different CAISO market processes.

A. The MRTU Tariff defines a number of categories of Generating Units so as to make clear which ones can be optimized in the various MRTU Unit Commitment processes running at different times. There is also another distinction that is used in this categorization, the distinction between Start-Up time and cycle time. Start-Up time is used in the conventional manner to refer to the time between a unit's receipt of a Start-Up instruction and its capability to supply Energy to the grid. Cycle time refers to the minimum time between to successive starts of a unit, which includes Start-Up time, minimum run time, and any required shut-down and minimum-down time. The cycle time is used in the definition of Short Start units and is relevant to how the STUC commits Generating Units. It is important to note that the Fast, Medium, Long and Extra-long Start categories are mutually exclusive, whereas the Short Start category, because it is defined in terms of cycle time rather than Start-Up time, will have some overlap with the Fast and Medium Start categories.

The categories and their uses may be summarized as follows:

- Fast Start units have a Start-Up time less than two hours and can be committed in the RTUC or STUC.

- Short Start units are the one category that is defined in terms of cycle time rather than Start-Up time. Short Start units have a cycle time less than five hours and can be fully optimized with respect to this cycle time in the STUC. The STUC, thought it explicitly optimizes over a 255-minute period (seventeen 15-minute intervals), is actually run 47.5 minutes before that period starts, thus it sees five hours into the future. The definition of Short Start is also relevant to the Resource Adequacy portion of the MRTU Tariff, as discussed in the testimony of Mark Rothleder.
- Medium Start units have a Start-Up time between two and five hours, and can be committed in the STUC.
- Long Start units have a Start-Up time between five and 18 hours and therefore can only be optimally committed in the DAM, either in the IFM or in RUC.
- Extra-Long Start units have a Start-Up time greater than 18 hours and as a result need to be started in advance of the DAM in order to be able to provide Energy to the grid in the target Trading Day. The CAISO will have a procedure for committing such resources on a two-day-ahead basis using Demand Forecasts and replicated Bids to estimate grid and market conditions two days into the future. For MRTU Release 2 the CAISO will consider and discuss with stakeholders the possibility of modifying the IFM or RUC optimization to cover a two-day time horizon to be able to commit such resources.

Q. Which Resources are eligible for economic Dispatch in the RTD?

A. As a general matter, any Resources that have Energy Bids in the RTM and are dispatchable on a five-minute basis are eligible for economic Dispatch in the RTD. This includes all capacity of internal Generating Units, Participating Loads and Dynamic System Resources (imports) that have associated Energy Bids. The RTD may also economically Dispatch Energy from Contingency Only Operating Reserves under certain circumstances, depending on which mode of RTD is being utilized.

Q. What are the modes of the RTD and how can Contingency Only Operating Reserves be used in the RTD?

A. The normal mode of RTD is the Real-Time Economic Dispatch ("RTED"), which runs every five minutes. The RTED in general will not utilize Contingency Only Operating Reserves, except when there is a shortage of Energy Bids to meet Real-Time Demand and the CAISO is facing imminent system emergency but there is no transmission or generation contingency, no significant outage or derate of a facility. In such cases the Contingency Only Operating Reserves will be included in the RTED with Energy Bid prices at the system Bid cap rather than their submitted Bid prices, to reflect the scarcity conditions. These Bid-cap Bid prices will be eligible to set Real-Time LMPs and thus provide a mechanism for scarcity pricing of Energy.

The second mode of RTD is the Real-Time Contingency Dispatch ("RTCD"), which is invoked when there is a transmission or generation contingency, which means a loss or significant derate of a facility. The RTCD can be invoked by the CAISO operators immediately upon identifying the need for it; the operators do not have to wait for the appointed time of the next RTED run. The RTCD incorporates the Contingency Only Operating Reserves at their actual Bid prices because circumstances are not scarcity condition, but reflect the explicit intended use of such reserves. It should be noted that under such conditions the CAISO operators may also issue a commitment instruction to a Generating Unit that is needed to address the contingency, rather than having to wait for the next RTUC run.

The third mode of RTD is the Real Time Manual Dispatch ("RTMD"), which is a fall-back Dispatch tool for CAISO operators in cases where the RTED or RTCD fails to converge upon a solution in a timely manner. The RTMD is a very minimal tool, however, in the sense that it simply provides a price-quantity Supply stack for the system, issues Dispatch Instructions and determines system-wide Energy clearing prices for each five-minute interval without enforcing internal transmission constraints. It is intended to be used extremely rarely.

Q. What price is paid to Resources Dispatched in the RTD?

A. Resources Dispatched in the RTD, as well as Generating Units that were Self-Scheduled in the RTM through the HASP, will be paid the appropriate ten-minute LMPs at their locations, subject to certain provisions including Uninstructed Deviation Penalties. The ten-minute LMPs are calculated for consecutive pairs of five-minute RTD intervals based on the five-minute LMPs calculated by the RTD.

The details of the price calculation and Real-Time settlement are discussed in the testimony of Dr. Farrokh Rahimi.

Q. Describe how the CAISO will procure Ancillary Services in the RTM.

A. As described above in the section on the HASP, the CAISO will procure AS on an hourly basis from import suppliers through the HASP optimization. In addition, as described above in the section on the RTUC, the CAISO will procure AS from Generating Units in Real Time on a 15-minute basis through the RTUC. Further details about AS procurement and settlement are discussed in the testimony of Dr. Farrokh Rahimi.

Q. How will the CAISO deal with positive and negative uninstructed deviations by resources in the Real-Time Market?

A. There are two aspects to this issue, the operational aspect and the financial aspect. With regard to the operational aspect, an important feature to be implemented in the RTD with start-up of the LMP markets will be Dispatch from telemetry. The Dispatch Instructions issued by the RTD will take as their point of reference a resource's actual operating point as indicated by telemetry. Thus, if a resource is deviating from its Schedule as modified by any CAISO Dispatch Instructions – an operating level referred to as the resource's Dispatch Operating Target or DOT – the RTD will not have to track such deviations in determining new Dispatch Instructions. Rather, the Dispatch Instructions resulting from each RTD run will instruct resources how to move relative to their actual operating levels at the time the RTD runs. This feature will minimize the operational impact of uninstructed deviations by Generating Units, because the RTD will always optimize relative to the latest accurate information about Generating Unit operation at each location.

The financial aspect of uninstructed deviations by resources will be addressed through the Uninstructed Deviation Penalty ("UDP"). The UDP is designed to provide effective financial incentives for resources not to deviate from their Schedules as modified by CAISO Dispatch Instructions and therefore is calculated for each ten-minute settlement interval in Real Time. For resources that over-generate beyond a reasonable tolerance band the UDP will essentially reverse what they would have been paid for the Energy, so they cannot earn anything from such over-generation. For resources that under-generate beyond the tolerance band, the UDP will calculate a penalty equal to 50 percent of the Real-Time ten-minute settlement price at that location, which is charged in addition to the cost of replacing the entire amount – with no tolerance band – of Real-Time Energy that was not provided by the resource.

G. <u>Treatment of Constrained Output Generators</u>

Q. What is a Constrained Output Generator?

A. A COG is a Generating Unit that can operate at only two levels: either completely turned off or at its maximum output, referred to as its PMax. It is termed constrained because it cannot be operated at any intermediate operating level.

Q. What special treatment of COGs is provided under MRTU?

A. In the SCUC optimization, the prices can only be set by resources that are flexible, that is, capable of moving up and down in small increments so that they can be adjusted continuously to achieve the optimum value of the objective function. By their nature, COGs are not flexible, and therefore the SCUC will not utilize these resources to set prices. Several parties, as well as the Commission, expressed concern that prices would be depressed during peak hours as an unintended and undesirable consequence of this property of the SCUC optimization. Because COGs are typically combustion turbines with relatively high heat rates that are run under peak conditions, it was argued that in such conditions the higher operating costs of these units should be reflected in higher prices. In its October 28, 2003 Order, the Commission directed the CAISO to review its approach to setting prices in the forward market and develop a pricing mechanism for COGs that would allow a COG to set the price for those Dispatch Intervals in which any portion of its output is needed to serve Real-Time Load. October 28, 2003 Order at P 89. After much discussion of this matter in filings and Commission-sponsored technical conferences in 2004, the CAISO filed with the Commission a proposal that would allow COGs to set the price under certain circumstances. .

Q. How will MRTU enable COGs to set prices in the IFM?

A. In the IFM, COGs will be modeled as flexible resources. When they submit their three-part bids they will include Start-Up and Minimum Load but no Energy Bid.

The software will construct an Energy Bid that has a single price for all MW of their PMax by dividing the Minimum Load Bid by the PMax to determine a price per MWh. The IFM will then use this energy Bid to optimize each COG as if it could operate at any point between zero and its PMax. Thus for any hour in which the COG is scheduled at an intermediate operating level the SCUC will see it as a flexible resource and the resource will be eligible to set prices just like any other flexible resources.

Q. How will COGs be modeled in RUC and will they be eligible to receive RUC Availability Payment if they are not RA resources?

A. RUC will treat COGs as constrained because RUC is a reliability procedure and it must make procurement decisions based on an accurate representation of resource operating parameters. One effect of this principle is that RUC will either select the entire capacity of a COG or none at all. If the COG was scheduled in the IFM then RUC will assume that it will run at PMax, so its RUC schedule will equal its PMax. If the COG was not scheduled in the IFM then RUC will optimally commit it or not, so its RUC schedule will be either its PMax or zero. Another effect of the RUC's use of actual resource operating parameters is that a COG will not be eligible to receive the RUC Availability Payment even if it is not a RA resource. The reason is that the capacity eligible for the Availability Payment – for all resources, not just COG – is the difference between the resource's RUC schedule minus the maximum of its IFM schedule or its PMin. No RUC Availability Payment is warranted for the PMin MW of a unit because those MW are covered by Minimum Load Cost Recovery. In the case of a COG, RUC optimizes based on the COG's true operating parameters, and because PMin equals PMax for the COG its RUC schedule can never be higher than its PMin, so there are no MW of COG capacity eligible for the RUC Availability Payment.

Q. How are COG treated in the RTM?

A. In all the processes of the RTM – the RTUC, the RTD and the STUC – COG are treated as constrained for purposes of unit commitment and Dispatch because in the actual operating hour all Dispatch Instructions must be feasible. In the IFM it is not a problem if the COG is scheduled at an operating level at which it cannot operate, because the IFM Schedule is essentially a financial position for the resource and it will be adjusted in a later market process. If the COG is scheduled at an infeasible operating point in the IFM, then this will be its Day-Ahead Schedule going into the RTM, and the RTM must issue Dispatch Instructions that are feasible. The RTD will therefore Dispatch the COG either to zero or its PMax. This does not prevent the COG from setting prices in the RTD, however, because the RTD has a separate "pricing run" that follows each "dispatch run," and in the pricing run the COG is modeled as a flexible resource using the Energy Bid calculated from its Minimum Load as described above. If any portion of the COG capacity is cleared economically to meet Demand in the RTD, it will be eligible to set the price like any other flexible resource.

Q. Are there any restrictions on how the COG can Bid under the approach described above?

A. The COG is subject to the same rules regarding bidding of Start-Up and Minimum Load as other resources. That is, these Bids can be either cost-based, in which case they are adjusted to reflect current gas prices, or they are Bid-based, in which case the resource can submit any values it likes for these Bids but they will be fixed for six months and cannot be varied on a day-to-day basis.

Q. Is there any alternative available for a COG that wants more flexibility to change its Bid on a daily basis?

A. Yes. As an alternative to the treatment described above, the COG can elect to be treated the same as other flexible units by specifying in its Master File data a PMin value that is a few MW less than its PMax. Under this option the COG would still be subject to the regular rules for the Start-Up and Minimum Load Bids, but would be able to also submit a separate Energy Bid for the Dispatch range between PMin and PMax.

H. <u>Treatment of Intermittent Resources</u>

Q. What are Intermittent Resources, and what properties of them require special treatment in the CAISO markets?

A. Intermittent Resources are renewable resources that are not dispatchable because their output depends on environmental conditions. Solar and wind generating resources are the main types of Intermittent Resources the CAISO markets must accommodate, and wind is the more significant in terms of total MW of capacity in California. The two main features of these resources that require some special treatment are (1) their limited ability to respond to Dispatch Instructions, because they produce whatever the prevailing weather conditions allow, and (2) the lack of reliable day-ahead forecasts of their output.

Q. What special provisions are incorporated in MRTU to address these features of Intermittent Resources?

A. I will answer this from the CAISO's perspective and from the Intermittent Resource operator's perspective. From the CAISO's perspective, the main problem to be solved is how to account for Intermittent Resources in establishing the RUC procurement target. They may be scheduled in the IFM, but from a reliable operations perspective the CAISO cannot assume that a 100 MW Day-Ahead Schedule for an Intermittent Resource is as dependable as the same schedule for a dispatchable resource. The CAISO must therefore decide how to consider the Day-Ahead Schedule of an Intermittent Resource in setting the RUC target, or whether to utilize a different estimate altogether, such as some historical average output data, and utilize the Day-Ahead Schedule at all. The present tariff filing does not offer a solution to this problem. The CAISO will address it during the coming months in the process of developing a Business Practice Manual on the RUC Procurement Target.

From the perspective of the Intermittent Resource operator the main problem with respect to the CAISO markets is how to minimize exposure to charges for Real-Time Imbalance Energy and Uninstructed Deviation Penalties given the fact that the operator cannot control the output of the resource to stay on its Hour-Ahead Schedule. When HASP and RTM bidding close at 75 minutes before the Trading hour, the available forecasts for Intermittent Resources are much more accurate than Day-Ahead, but they are still not generally right on target and, moreover, the output will not remain constant over the hour. As a result the resource operator is exposed to Imbalance Energy and UDP and has no way to control this exposure through its operating behavior. The CAISO has developed a program to deal with this problem, called the Participating Intermittent Resource Program ("PIRP"). The PIRP was first implemented in 2004 and will be continued under MRTU.

Q. Please describe how the PIRP addresses the Intermittent Resource's exposure to Imbalance Energy and UDP charges.

A. For the purpose of this testimony I will describe the PIRP from the MRTU perspective and ignore details that are only relevant under today's CAISO market design. First note that participation in the PIRP is voluntary. It provides certain benefits to the participants and imposes certain responsibilities on them. The main responsibilities on the Participating Intermittent Resource ("PIR") are to (1) pay fees to support the cost of an independent entity, a Forecast Service Provider ("FSP") who produces forecasts of output for each PIR, and (2) submit a Self-Schedule to the HASP and RTM that equals the FSP's forecast for the PIR. In return the PIR gets two benefits that address the concerns I mentioned above.

First, the PIR's Real-Time deviations, though tracked on an interval basis, are summed over each month, negative deviation MWh are netted against positive deviation MWh, and the net result is settled at the monthly weighted average Real-Time LMP at the PIR node. Second, the PIR is exempt from the UDP.

I. Congestion Revenue Rights

Q. What are Congestion Revenue Rights?

A. I will be very brief on this topic and just provide a summary description and a few explanatory comments, because CRRs are covered thoroughly in the testimony of Dr. Susan Pope and Dr. Scott Harvey. CRRs are financial instruments that enable their holders to hedge the variability in congestion costs in power markets with location-based pricing that reflects grid congestion, such as the LMP markets to be implemented under MRTU.

Q. How does the CAISO propose to define CRRs?

A. A point-to-point CRR will be defined by the following attributes: (i) a basic type, which is a CRR Obligation or CRR Option; (ii) a CRR Term, which will either a season or a month combined with a time-of-use period (on-peak or off-peak); (iii) a specific CRR Source and CRR Sink corresponding to nodes or aggregations of nodes of the FNM; and (iv) a MW quantity, which can be specified down to tenths of a MW. There will also be multi-point CRRs that can be specified with multiple Sources or multiple Sinks or both. In this case the complete specification of the CRR must include the MW quantity at each Source and Sink, and the total

MW at the Sources must equal the total MW at the Sinks. The settlement of CRRs in the daily CAISO markets will be based on the Congestion components of the LMPs that result in the Day-Ahead IFM for each hour.

Q. How does the CAISO proposed to make CRRs available?

A. The CAISO will conduct an annual CRR Allocation and Auction process for the release of seasonal CRRs, and a monthly CRR Allocation and Auction process for the release of monthly CRRs. In both cases the Allocation will be performed first, to be followed by the Auction. In all cases the CAISO will utilize a Simultaneous Feasibility Test and a DC version of the same FNM that is used in the CAISO markets to ensure that CRRs released in any Allocation or Auction process are simultaneously feasible, taking as fixed the CRRs that were released in all previous CRR processes for the same CRR Term. Eligibility to participate in the Allocation will be limited to LSEs serving Demand inside the CAISO Control Area and, subject to the requirements discussed below, to certain LSEs serving Demand outside the CAISO Control Area. CRRs will also be allocated to those merchant sponsors of transmission projects who do not receive regulated cost recovery through the grid access charges, but this allocation will be separate from the allocation processes for LSEs. The CRR Auction processes will be open to all parties who satisfy the creditworthiness requirements set forth in the CAISO Tariff.

Q. Why is participation in the Allocation process limited?

A. The Allocation process is based on the principle that consumers who support the embedded cost of the grid by paying access charges – and by extension the LSEs who serve them – should be entitled to an allocation of CRRs to enable them to hedge the volatility in locational prices under LMP. This is a forward-looking principle, in other words, the CRRs are allocated for a future CRR Term in which the LSE will be paying access charges to serve its Demand, rather than an entitlement based on past payment of access charges as some parties have argued. Given the principle just stated, CRR Allocation will be based on nominations by the eligible participants, not on economic Bids to buy CRRs, so there will be no clearing prices that result from the Allocation process and no payments by CRR recipients for the CRRs received, except in the case of LSEs serving Demand outside the CAISO Control Area as discussed below. In contrast the CRR Auction does not restrict participation, except as regards creditworthiness, because the Auction is based on economic Bids to buy CRRs and the winning Bids pay for their awarded CRRs at the clearing prices that result from the Auction.

Q. Are there any important limitations on the CRR Allocation and Auction processes?

A. Yes, there are a couple of limitations that will apply in Release 1, but these may be considered for changes in Release 2. First, only CRR Obligations will be offered in Release 1 of MRTU, except for merchant transmission sponsors who may request to be allocated CRR Options. Second, participants in the Auction cannot sell their CRR holdings through the Auction. For example, if a LSE receives a CRR from node A to node B in the CRR Allocation process and wants to sell it, the LSE cannot offer it for sale in the Auction. There is a way around this limitation, however. The LSE can Bid to buy a CRR of the same MW quantity from B to A at a negative price, and if this Bid is cleared the LSE will hold two CRRs that are financially offsetting in each hour. This is a bit more cumbersome than selling the original CRR, but the financial result is equivalent.

Q. Please describe how the CAISO proposes to provide CRRs to LSEs that serve Demand outside of the CAISO control area?

A. The CAISO proposes that LSEs with external Demand who utilize the CAISO grid to serve that Demand may nominate and receive CRRs through the same annual and monthly CRR Allocation processes that are performed for LSEs with internal Demand, subject to certain requirements. The first requirement is a demonstration of need based on the ownership of, or a contract for energy with a Generating Unit located within the CAISO Control Area. The second requirement is that the LSE make a pre-payment to the CAISO equivalent to the access charge (specifically the “Wheeling Access Charge” or “WAC”) for all hours of the term of the requested CRR, for each MW of CRR requested. Subject to these requirements, LSEs with external Demand will be able to request seasonal on-peak or off-peak CRRs through the annual allocation process, and monthly on-peak or off-peak CRRs through the monthly allocation process.

Q. What is the rationale for requiring pre-payment of the WAC in order to be eligible for CRR Allocation?

A. As mentioned above, the fundamental principle underlying eligibility for CRR allocation is that parties who support the embedded costs of the CAISO grid are entitled to an allocation of CRRs in accordance with the nature and extent of their support for these costs, and this is a forward-looking principle. The principle is that they've already received transmission service for their past access charge payments, so no future entitlement is appropriate, and the key question for eligibility is the extent to which they will continue to pay access charges during the term of the allocated CRRs.

LSEs who serve Demand inside the CAISO Control Area cannot avoid using the CAISO grid because of their physical or electrical location, hence cannot avoid paying access and Congestion charges. In contrast, LSEs with Demand external to the CAISO control area can avoid using the CAISO grid. The WAC pre-payment is therefore warranted because otherwise the LSE serving external Demand could obtain the CRR and then avoid paying any WAC or Congestion charges by not scheduling Exports from the CAISO grid, so that their allocated CRRs would become pure financial assets rather than needed hedging instruments.

Q. Why isn't ownership of, or a contract with, a Generating Unit within the CAISO Control Area sufficient to ensure that the entity must use the CAISO grid?

A. Consider an LSE whose Demand is outside the CAISO Control Area and who owns and operates a Generating Unit inside the CAISO Control Area. Under MRTU the LSE could simply Self-Schedule its Generating Unit or offer it into the CAISO's Day-Ahead IFM or RTM without any corresponding export of the Energy. The LSE could operate its Generating Unit and get paid in the CAISO Energy market, while serving its Demand from other sources that do not utilize the CAISO grid, thus completely avoiding any access or Congestion charges.

Thus the CAISO's proposal here is based on the rationale that external Demand and internal Demand 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. For the LSE with external Demand who fully intends to rely on the CAISO grid to serve that Demand, the pre-payment will be used to offset WAC charges incurred in the daily CAISO markets.

During public meetings held on June 21, 2005, and August 18, 2005, the CAISO reviewed with stakeholders how other ISOs have awarded hedging instruments to entities with external Demand, and discussed alternatives that might be suitable for the CAISO. In addition, Dr. Scott Harvey and Dr. Susan Pope – who also address this topic in their testimony – provided an overview of the approaches of other ISOs and showed these to be essentially equivalent to what the CAISO is now proposing. The presentations used in those meetings and the written comments from stakeholders on those discussions have been posted on the CAISO website. The stakeholder comments clearly reveal that there are polarized views among certain entities on this issue.

Given the flexibility external Demands have with respect to their use of the CAISO grid and the resulting uncertainty of the linkage between their receipt of CRRs and their payment of CAISO access charges, pre-payment of access charges for the CRR term is an appropriate requirement for external LSEs to be able to obtain CRRs in the allocation process. Such pre-payment gives them a significant benefit by enabling them to obtain their desired CRRs in advance of the Auction process, in which they would otherwise have to compete with all parties eligible for the Auction. The testimony offered by Dr. Scott Harvey and Dr. Susan Pope endorses the fairness of this approach and its consistency with the FERC-approved practices of eastern ISOs.

Q. Are there limitations on the amount of CRRs that can be requested by LSEs with Demand external to the CAISO Control Area?

A. Yes. In addition to demonstrating ownership of or contractual rights to Energy from a Generating Unit within the CAISO Control Area, as mentioned above, LSEs with external Demand will be required to provide historical data showing their hourly exports from the CAISO grid at the Scheduling Point that they wish to designate as the CRR Sink in the allocation process. In other words, the equivalent of a load duration curve for the hours corresponding to the term of the desired CRR, but for the amount of exports at the CRR Sink of the desired CRR. This duration curve will be used to calculate a MW upper bound that applies to the entity's CRR requests at each requested CRR Sink.

Q. Are there circumstances when LSEs with external Demand would get refunds for all or part of the WAC they have pre-paid?

A. Yes. Because the CRR Allocation process enforces a Simultaneous Feasibility Test ("SFT") the LSE with external Demand may be allocated fewer than the full amount of requested CRRs for which it pre-paid. In this case the CAISO will refund to that LSE, within a reasonable time after the Allocation process has concluded, the pre-payment amount corresponding to requested CRRs that were not awarded.

Q. Please describe how the CAISO proposes to provide CRRs to the sponsors of merchant transmission projects?

A. The basic choice the merchant sponsor has to make is between regulated recovery of its investment cost through CAISO access charges, or an allocation of CRRs. If it chooses the first there is no allocation of CRRs. If it chooses CRRs, then the CAISO will offer the sponsor's choice of CRR Options or CRR Obligations, in a quantity and geographic source and sink pattern that is commensurate with the transfer capacity the sponsor's project adds to the CAISO grid, as determined based on engineering studies. It is important to note that this concept of added transfer capacity does not mean simply the capacity rating of the merchant sponsor's new facility or upgrade. The exact methodology for this determination has been discussed to some extent with stakeholders, and the CAISO has studied the approaches used by other ISOs for this purpose, but at this time the preferred methodology has not been finalized. The CAISO intends to reopen this matter with stakeholders during the coming year, and will develop a Business Practice Manual which specifies the procedures to be used for determining the CRRs for which the merchant sponsor would be eligible.

Although the methodology is still being developed there are some further details and principles that the CAISO has discussed with stakeholders. First, the CRRs allocated to the merchant sponsor would be good for the life of the transmission facility or thirty years, which is in line with the duration of similar financial rights allocated to developers of transmission infrastructure by PJM. Second, the merchant transmission sponsor's entitlement for CRR Options would begin when their transmission projects have been energized and operational control has been turned over to the ISO.

Q. How will merchant transmission projects affect the CRRs released to other parties?

A. Once operational, the merchant transmission facilities will be modeled in the FNM used for subsequent CRR Allocations and Auctions, and the CRRs given to the merchant sponsor will be modeled on the FNM as fixed CRRs to maintain revenue adequacy of the CRRs subsequently released to other parties. In some cases, particularly if the merchant project is powered in the middle of a CRR cycle, the CAISO might require the merchant sponsor to accept counterflow CRRs to maintain the feasibility and the financial value of previously awarded CRRs.

J. <u>Existing Transmission Contracts (“ETCs”)</u>

Q. What are Existing Transmission Contracts (“ETCs”) and why is there a need for special treatment for ETCs under MRTU?

A. ETCs are contractual agreements established prior to the creation of the CAISO by which a Participating Transmission Owner (“PTO”) is obligated to provide transmission service to another party, using transmission facilities owned by the PTO that have been turned over to CAISO operational control.

ETCs were created when one party to the contract, the Participating Transmission Owner, both owned and operated their portion of the transmission grid. The cost for transmission service was negotiated and agreed upon by both parties, and then embedded in the terms and conditions of these long-term contracts. Thus, when the CAISO became the transmission operator for the PTO’s transmission facilities, the transmission service component of these pre-existing contractual arrangements were honored by granting ETC holders unique operational and settlement arrangement advantages, such as the reservation of transmission capacity and exemption from the access and Congestion charges associated with transmission service.

The CAISO must continue to ensure that these existing contractual rights are fully honored with the change from today’s zonal market design to the LMP markets of MRTU which utilize the FNM to manage Congestion accurately in all markets. The CAISO’s proposed management of ETCs under MRTU still provides unique treatment for ETC Self-Schedules and a special settlement mechanism, and does so in a manner that minimizes the impact on the operation of the FNM-based Day-Ahead and Real-Time optimization. The differential treatment of ETC Self-Schedules as compared to non-ETC Self-Schedules is necessary for the CAISO to respect the transmission component of these contracts for as long as they remain in existence.

Q. How does the CAISO's LMP-based market propose to honor ETCs?

A. There are two aspects of the proposed treatment of ETCs under MRTU, the scheduling aspect and the settlement aspect. With respect to scheduling, the CAISO will provide scheduling priority to valid ETC Self-Schedules in all CAISO markets for which the ETC holder has scheduling rights under the terms of their contract. Thus if the ETC holder's rights expire after the DAM, the CAISO will provide scheduling priority in the IFM but not in the RTM. If the ETC holder's rights extend to the Hour-Ahead time frame, the CAISO will also provide scheduling priority for any valid ETC Self-Schedule changes submitted by the close of the HASP and RTM bidding process. And if the ETC holder's rights extend beyond the Hour-Ahead time frame the CAISO will honor valid ETC self-schedule changes submitted up to 30 minutes prior to the start of the operating hour. With respect to settlement, valid ETC Self-Schedules will receive a special treatment called the "perfect hedge," which exempts them from any Congestion charges or payments in those markets for which they have scheduling rights under their contracts. In addition they will be exempt from transmission access charges (TAC or WAC) as they are today.

Q. Will the CAISO reserve transmission for ETCs as it does today?

A. Yes, transmission reservations under MRTU will be very similar to what is done today. One difference, however, is that under MRTU the reservations will be held only for those markets for which the ETC holder has scheduling rights, whereas today the CAISO holds all ETC reservations through the Day-Ahead and Hour-Ahead markets for all ETCs. Under MRTU, for those ETCs that have rights to utilize transmission capacity on the interties, the CAISO will reserve enough capacity in the DAM to accommodate the full exercise of the ETC holder's rights. If the ETC holder's rights expire after the DAM, then the IFM will provide scheduling priority to the valid submitted ETC Self-Schedule but will release any MW of the reserved capacity for that ETC that is not used by the valid ETC Self-Schedule, and that unused ETC capacity will remain available for other uses for all subsequent CAISO markets. Alternatively, if the ETC holder's rights extend to the Hour-Ahead time frame, then the IFM will continue to reserve the entire amount of ETC capacity in the IFM even if only a portion of it was Self-Scheduled in the IFM. Analogously, if this ETC holder's rights expire after the Hour-Ahead, then any reserved ETC capacity that is not used by a valid Hour-Ahead ETC Self-Schedule is released for other uses in the HASP, whereas if the ETC holder's rights extend beyond the Hour-Ahead the entire amount of the ETC reservation will continue to be reserved in the HASP.

Q. Will the CAISO reserve any transmission capacity internal to the CAISO grid for ETCs?

A. No, that is completely unnecessary under LMP. If the ETC holder has rights to deliver energy from an internal Generating Unit to its internal Demand location, it simply submits a valid Self-Schedule in any market in which it has rights and the SCUC optimization for that market will assign the appropriate scheduling priority and Dispatch resources with economic Bids as needed to accommodate the ETC Self-Schedule.

Q. Will ETC Holders be allocated CRRs?

A. No, the perfect hedge is better than CRRs because it perfectly reverses all Congestion charges associated with valid ETC Self-Schedules, whereas CRRs provide a revenue stream from hourly Congestion charges that may not exactly offset the ETC holder's exposure to those Congestion charges.

Q. Will the perfect hedge treatment of ETCs adversely affect the holders of CRRs?

A. Clearly the perfect hedge will result in the CAISO not collecting some of the Congestion charges that would normally be collected from all accepted IFM schedules. Such a systematic under-collection of Congestion revenues must somehow be compensated for, or it will lead to the inability to pay CRR Holders the full value of their CRRs. The risk of such negative impact on CRR Holders can be minimized by adjusting the release of CRRs to compensate for the perfect hedge. The CAISO will make a careful effort to perform such adjustments in as accurate a way as possible, to minimize both the risk of revenue shortfall for CRR

Holders as well as the opposite risk of excessively limiting the release of CRRs. For each CRR Allocation process, the CAISO will develop, based on historical data and in collaboration with the ETC parties, a set of CRR nominations for each ETC that reflect the best estimate of the Congestion revenue stream associated with providing the perfect hedge to that ETC. The CAISO will include these nominations in the CRR Allocation process along with the nominations of the other participants in the Allocation, and will assign them a higher priority in the SFT to reflect the CAISO's commitment to the perfect hedge settlement. The SFT will then release to the other participants only the amounts of CRRs that are simultaneously feasible and expected to be revenue adequate, given the perfect hedge treatment of the ETCs. The modeled ETC CRRs will of course not be created or issued to any party, because they will not exist except as a device used by the SFT to safeguard the revenue adequacy of the CRR nominations it clears for the other participants.

Q. How is a submitted ETC Self-Schedule determined to be valid or not.

A. The PTO who entered the contract with the ETC holder will provide to the CAISO a set of instructions that specify the ETC holder's rights to transmission service under the contract. These instructions will comprise a data file for each ETC against which the CAISO's Bid validation procedures will be able to validate the submitted ETC Self-Schedule and determine whether it is valid. Thus the data file will need to include, at a minimum, eligible grid locations for injecting and withdrawing power, maximum MWh quantities, and required scheduling deadlines. In addition, ETC Self-Schedules must be balanced to be valid, that is, equal MWh of Supply and Demand, without accounting for losses. In some cases the ETC holder's rights may need to be used by more than one SC, for example, if the ETC holder is receiving Energy to serve its Demand from a Generating Unit assigned to a different SC. The validation data file will therefore also need to specify a list of SCs eligible to use the Contract Reference Number which is unique to each ETC. When the ETC Self-Schedule is submitted to the CAISO DAM or HASP for the HASP and RTM the validation systems of those markets validate the submitted ETC Self-Schedule against the validation data file.

Q. What does the CAISO do if a submitted ETC Self-Schedule is not valid?

A. The MRTU software will send a message to the relevant SC or SCs in this case, and if there is time the SCs may resubmit the Self-Schedule. If the Self-Schedule is not valid by the time the relevant market closes, the IFM will treat it like a non-ETC Self-Schedule for scheduling purposes. That is, the ETC scheduling priority will not be provided, but the ETC Self-Schedule will still be included in the market optimization on par with non-ETC Self-Schedules. This does not necessarily mean, however, that the submitted ETC Self-Schedule also loses the ETC perfect hedge settlement treatment. If the ETC Self-Schedule fails validation only because it is not balanced, the CAISO will still provide the perfect hedge settlement treatment for the valid balanced portion of the schedule, which is defined by the minimum of the valid injection MW or the valid withdrawal MW. If the ETC Self-Schedule consists of a single injection location and single withdrawal location this adjustment is straightforward. If multiple injection or withdrawal locations are involved, however, pro rata reduction on the injection side, the withdrawal side or both will be needed to create a valid balanced portion of the submitted Self-Schedule for settlement purposes. Similarly, if the ETC Self-Schedule fails validation because it exceeds the allowable MW limits but uses valid injection and withdrawal locations, the MRTU software can determine a valid, balanced portion of the Self-Schedule for settlement purposes, applying pro rata reduction if necessary when there are multiple injection or withdrawal locations. These adjustments are fairly straightforward because there is a valid, balanced ETC Self-Schedule contained within the submitted Self-Schedule that is identifiable by means of fairly simple rules. Beyond these simple cases, however, the MRTU software will most likely not be able to perform suitable adjustments and the ETC holder would lose the ETC settlement treatment as well as the ETC scheduling priority.

Q. Have these ETC scheduling and settlement features been reviewed and ruled upon by FERC?

A. Yes, the major features have been addressed in CAISO filings and in FERC orders on those filings. The CAISO's Amended Comprehensive Market Design Proposal filed in July 2003 set the direction for the CAISO to work with stakeholders to develop an appropriate mechanism for honoring the ETCs under the proposed MRTU market design. The CAISO conducted a series of stakeholder meetings throughout 2004 that led to the development of the scheduling provisions and the perfect hedge settlement features that I described above. The CAISO submitted these elements to FERC for conceptual approval on December 8, 2004.[5] FERC's Guidance Order[6] issued on February 10, 2005, authorized the CAISO to proceed with software development of the IFM and other market processes that would have to incorporate the special functionality required for the proposed treatment of ETCs under MRTU.

Notably, the December 8, 2004, ETC proposal that FERC considered dealt only with the ETC scheduling, validation and the treatment of Congestion costs associated with valid ETC Self-Schedules. That proposal did not include the treatment of losses and other charges to ETC Self-Schedules.

Q. How does the CAISO propose to deal with charges other than Congestion for Self-Schedules that utilize ETC rights?

A. The CAISO reviewed issues related to charges other than Congestion that would affect ETCs with stakeholders in meetings held on July 14, August 17, September 16 and October 6, 2005, as part of the overall stakeholder process for finalizing MRTU policy issues. Stakeholders also provided written comments on these issues. In those meetings the CAISO clarified that, upon MRTU implementation, ETCs will be exempt from Wheeling Access Charges in the Day-ahead and Real-Time markets for the valid, balanced portion of their ETC Self-Schedules. This

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[5] "Proposal for Honoring Existing Transmission Contracts Under the California Independent System Operator Corporation's Amended Comprehensive Market Design Proposal" filed December 8, 2004 in Docket No: ER02-1656-021.

[6] *California Independent System Operator Corp.*, 110 FERC ¶ 61,113 (2005).

exemption is consistent with current practice. Furthermore, valid ETC Self-Schedule changes submitted after the close of the HASP and RTM will not be exposed to uninstructed deviation charges.

The exposure of ETC Self-Schedules to the Grid Management Charge ("GMC") under MRTU will be determined as part of the stakeholder process reviewing the entire GMC, which will be conducted in 2006. ETC schedules currently are exempt from the Congestion Management component of GMC but are subject to other components of the GMC.

Q. How does the CAISO propose to deal with transmission losses associated with ETC schedules?

A. ETC Self-Schedules will be treated the same as non-ETC schedules with respect to charges for losses. The CAISO considered alternative approaches for treatment of losses associated with ETC schedules, in consultation with stakeholders during the Summer 2005 MRTU stakeholder meetings. Some ETC holders sought a complete rebate or exemption from the marginal loss charges associated with their valid, balanced ETC Self-Schedules, based on the argument that they had paid for losses under the terms of their ETCs. This approach was rejected because such a rebate or exemption would cause the CAISO to fail to recover a portion of the actual cost of congestion to the system, and would impose this cost on other parties across the market rather than containing it between the two parties to the contract. The CAISO finally concluded that the most effective way to contain the cost of losses between the ETC contract parties would be to charge ETC Self-

Schedules for losses on the same basis as other grid users, and allow the parties to the contract to work out between them whether some compensation from one to the other is warranted. With this approach the CAISO would stay removed from interpreting these contracts, avoid favoring particular parties to a contract, and also avoid causing a cost associated with ETC Self-Schedules to be spread to the rest of the market. Moreover, the prompt, direct credit-back of the net revenues collected from marginal losses, which I discussed earlier in this testimony, will substantially reduce the magnitude of this concern for the parties involved.

Q. Can ETC rights holders utilize Inter-SC trades to facilitate their perfect hedge treatment of Congestion charges?

A. The rules for Inter-SC Trades were carefully crafted in the context of a settlement proceeding regarding bilateral "seller's choice" energy contracts, which was conducted during 2004 by FERC. Part of the settlement resolution required the CAISO to define the scope of Inter-SC Trades precisely and fairly narrowly, with the result that many of the locations that would be useful to ETC holders for Inter-SC Trades may not be eligible locations for Inter-SC Trades. This is not really a limitation on how parties to contracts – ETCs or any other contracts – can settle between themselves. It is important to understand that Inter-SC Trades, as I explained earlier in this testimony, are merely a convenient way for two parties to effect a bilateral settlement between them utilizing the CAISO settlement system. Although it might be more convenient to use the CAISO settlement system, they could perform the same bilateral settlement directly between themselves based on locational prices posted by the CAISO for each market.

The CAISO has made other provisions in this tariff to facilitate the settlement of ETCs. One of these is the ability to register, in the ETC validation data file, more than one SC who is eligible to use the same ETC Contract Reference Number. A related feature is the ability to designate, also in the ETC validation data file, the specific SC who is to receive the perfect hedge congestion charge credit. For most purposes needed by ETC holders these two provisions offer an effective alternative to using Inter-SC Trades.

Q. Will the CAISO's role change under MRTU with respect to interpreting Existing Transmission Contracts?

A. No. The CAISO does not interpret contracts between other parties that were created prior to the CAISO's formation. Section 16.4 of the MRTU Tariff details a clear process for the specification of contractual rights by the parties to each ETC, so that the CAISO's role is limited to implementing those rights as specified, by following the procedures described above.

K. Transmission Ownership Rights ("TORs")

Q. What are TORs?

A. A Transmission Ownership Right is the right to use 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.

Q. Please describe how TORs will be treated under MRTU.

A. TORs will get the second highest scheduling priority in the CAISO markets, second only to RMR Schedules needed to ensure local grid reliability and they will be exempt from Wheeling Access Charges and Congestion charges in both the Day-Ahead and Real-Time markets for the balanced and valid portion of their TOR schedules. The perfect hedge mechanism will apply for reversing Congestion charges for TOR schedules, in the same way as for ETC schedules. This means, of course, that the CAISO will also have to model TORs appropriately in the CRR Allocation and Auction processes, so that CRR Holders are not adversely affected financially by the perfect hedge treatment of TORs.

Q. Are there any differences in the CAISO's proposed treatment of TORs compared to the CAISO's proposed treatment of ETCs.

A. Yes. TORs, in continuation of the current policy (which is based on the interpretation of the April 7, 1998 GMC Settlement Agreement), will be exempt from UFE, neutrality and imbalance energy offset charges. Also, as noted above, TORs have higher scheduling priority than ETCs.

Q. Will the CAISO's proposed policy be applied to all TORs?

A. The proposed policy will apply to all TORs, except to the extent that a provision in a FERC-accepted and existing settlement agreement or operations agreement expressly provides for different treatment of a TOR than specified in the policy.

The CAISO does not intend that the proposed policy would supersede the requirements of those agreements. An example of such an agreement would be the Settlement Agreement and SWPL Operations Agreement the CAISO entered into with SDG&E with respect to the Southwest Powerlink. (See Docket Nos. ER04-115-002, et al., and ER05-1013-000). When those or any similar agreements expire, or otherwise terminate, the CAISO would apply the policy described above to the associated TORs.

L. New Participating Transmission Owners Converted Rights ("CVRs")

Q. What are Converted Rights?

A. Subsequent to the initial start-up of CAISO operations in 1998, certain entities chose to sign the Transmission Control Agreement and turn over Operational Control of their transmission facilities and Entitlements to the CAISO. These entities became what are called "New Participating Transmission Owners" ("NPTOs"). The transmission capacity associated with the contractual rights and associated with owned facilities turned over to CAISO Operational Control were converted into Firm Transmission Rights ("FTRs"), defined, under the current CAISO Tariff, on specific transmission paths at specific inter-zonal interfaces. Today's FTRs entitle their holders to a revenue stream based on Congestion charges and to certain scheduling priorities, in the Day-Ahead Market, for the transmission of energy across their corresponding inter-zonal interfaces.

In accordance with Amendment 27 of the CAISO tariff, these Converted Rights exist until the end of the Transmission Access Charge Transition Period on December 31, 2010, or for a shorter period if the converted rights were associated with an ETC that would terminate prior to that date. After this transition period, the NPTOs are to be treated the same as the CAISO's Original Participating Transmission Owners.

To date, the cities of Anaheim, Azusa, Banning, Pasadena, Riverside, and Vernon, California, are the only entities who have become NPTOs and elected to join the CAISO and convert the transmission capacity of their facilities and Entitlements into FTRs.

Q. How does the CAISO propose to transition the Converted Rights held by these NPTOs into commensurate rights when LMP is implemented?

A. After discussion with and the concurrence of the Southern Cities, the entities who currently hold these CVRs, the CAISO proposes to provide them a scheduling and settlement mechanism that: (1) fully offsets the CAISO Congestion charges for each CVR party's scheduled use of its Converted Rights in the Day-Ahead IFM, and (2) provides scheduling priority for such Day-Ahead schedules. In essence, the CAISO has tried to continue to honor the commitment made to the New Participating TOs for the remainder of the Transition Period approved by the Commission in Amendment No. 27.

This mechanism is similar to the proposed treatment of non-Converted Rights under MRTU, in the manner in which it provides scheduling priority and the "perfect hedge" offset to Congestion charges and payments associated with a CVR party's Day-Ahead use of its Converted Rights, but for CVR holders both the scheduling priority and the perfect hedge settlement will apply only to the DAM. This treatment is equivalent to today's FTRs which only apply the scheduling priority and Congestion payments based in the Day-Ahead Timeframe; however, the proposed perfect hedge for the New Participating TOs will differ from today's FTRs in the sense that the perfect hedge will reverse actual charges and not provide a revenue stream as do FTRs today or CRRs would do under MRTU.

Q. How will the CAISO implement this conversion from the current treatment based on FTR holdings to the MRTU treatment of CVRs?

A. The CAISO proposes to work with each CVR party to specify its Converted Rights in a form that is consistent with the representation in the FNM of the transmission they turned over to CAISO Operation Control and also consistent with the LMP markets being implemented under MRTU. In particular, such specification will entail creating a validation data file analogous to those created for ETCs, indicating how each CVR party may schedule the use of its Converted Rights by identifying eligible injection and take-out nodes and maximum MW quantities, with provision for the bi-directional nature of the Converted Rights where relevant. Then, in the daily running of the Day-Ahead IFM, when a CVR party submits a balanced Self-Schedule that is consistent with such specification, the IFM will afford that schedule the same level of scheduling priority as will be given to non-Converted Rights..

Once the submitted Self-Schedule is cleared in the IFM, the associated Congestion charges (or payments in the event the schedule creates counter-flows) will be fully reversed in the settlement process.

It should be noted that any Self-Schedules submitted by a CVR party in the HASP and any Real Time deviations will be subject to the same rules and will be treated in the same manner as HASP submissions and Real Time deviations of other grid users, without either the scheduling priority or the "perfect hedge" Congestion offset that are provided in day-ahead. Moreover, consistent with today's practice with respect to Converted Rights, there will not be any linkage between post-day-ahead CAISO market charges and payments and a NPTO's Transmission Revenue Requirement.

Q. What is the duration of this CVR treatment?

A. The scheduling priority and perfect hedge mechanism for converted rights will be in effect from the start-up of the MRTU markets until the end of the Transmission Access Charge Transition Period on December 31, 2010, unless the Converted Right is associated with an ETC that expires earlier. Once the Transition Period ends, each CVR party will still be entitled, as a LSE serving Demand within the CAISO control area, to nominate and receive CRRs in the CRR Allocation processes on the same basis as other such LSEs.

Q. Does the CAISO's proposed treatment for CVRs preclude the allocation of CRRs to the CVR entities during the Transition Period?

A. No. To the extent a CVR party is also a LSE serving Demand inside the CAISO Control Area it will be eligible to receive CRRs based on the amount of its Demand that is not hedged against Congestion charges under the perfect hedge. Because the perfect hedge is defined based on the amount of transmission turned over to CAISO Operational Control and not based on the CVR party's Demand, the CVR perfect hedge may not be sufficient to provide the same degree of Congestion hedging for its Demand as the party would be entitled to as a LSE.

Q. Describe how this would work.

A. The principle is to allow each CVR party to nominate CRR Obligations in the CRR Allocation process on the same basis as other LSEs serving internal Demand, but with eligible quantities that are calculated based on the amount of Demand that is not covered by the perfect hedge mechanism. There are two cases to consider:

For some CVR parties the FNM specification of the Converted Rights will extend all the way from the injection nodes for a party's resources to the take-out nodes for the party's Demand. In this case the party will be able to utilize the perfect hedge to serve its Demand – up to the Converted Rights MW quantity – without needing any additional CRRs for that quantity of Demand. If the party's LSE-based CRR eligibility calculated on the full amount of its Demand is greater than its CVR MW quantity, the party will be eligible to nominate CRR

Obligations to make up the difference, in accordance with the process for the other LSEs. If the party's LSE-based eligibility is less than its CVR MW quantity, then it would not be eligible to nominate CRRs in the CRR Allocation process.

In other cases, the Converted Rights may not extend all the way to the party's Demand, in which case the party will qualify for additional CRRs to hedge the same MW of LSE-based eligibility that is covered by the perfect hedge, to cover the Congestion cost exposure between the point where the converted rights end and the Demand is located. Suppose, for example, that the party's 100 MW of Converted Rights go from generator injection node A to a specific destination node B on the CAISO grid. Suppose the party's Demand-based eligibility is 180 MW, its Demand is scheduled and settled at the SCE-LAP, and the party does not have Converted Rights to deliver energy from node B to its Demand. In this case the City gets the perfect hedge for its Day-Ahead Self-Schedules from node A to node B up to 100 MW, and is also entitled to an allocation of CRR Obligations up to 180 MW because this full amount of Load will be exposed to Congestion charges. When this City nominates CRRs in the CRR Allocation process, it could nominate CRRs whose source is node B to create a complete Congestion hedge from node A to the SCE-LAP (*i.e.*, perfect hedge from A to B, plus CRR Obligations from B to SCE-LAP).

Q. When the Transition Period ends would a CVR party be able to utilize the Priority Nomination Tier of the CRR Allocation process to "grandfather" its expiring CVR?

A. Yes. The proposed annual CRR Allocation process has three tiers, the first of which is a "priority nomination tier" ("PNT") in which LSEs may nominate CRRs they hold in the current year for high-priority renewal for the upcoming year. It is reasonable, when the Transition Period ends, to allow CVR parties to nominate their expiring CVR along with their current CRR holdings in the PNT, subject to the same limits on PNT quantities as apply to other LSEs. Furthermore, if a CVR entity decided to terminate its converted rights privileges and operate fully under the CAISO's CRR allocation rules earlier than the end of the TAC Transition Period, the CVR entity will be allowed to exercise the PNT capability in the first applicable running of the CAISO's annual CRR allocation process.

Q. Are other entities eligible for CVRs or the perfect hedge treatment under MRTU?

A. Yes. The approach described above will be applicable to any parties that convert their transmission rights and become NPTOs prior to the end of the Transition Period on December 31, 2010. If they convert prior to MRTU start-up they will function as CVRs under today's provisions, and then will convert to the perfect hedge approach once MRTU starts up. If they convert after MRTU starts up but prior to December 31, 2010, they immediately become eligible for the perfect hedge treatment. If they convert after December 31, 2010 there will be no special treatment, which is consistent with the Transition Period specified in the current Tariff

Q. Does this conclude your testimony?

A. Yes, it does.

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