UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and Structure	))	**Docket No. RM01-12-000**

Comments of the California Independent System Operator Corporation on the Commission's RTO Workshop

- Lessons Learned After Three Years of Operation -

The California Independent System Operator Corporation (CA ISO) appreciates the opportunity to provide comments on the Commission's RTO Workshop, held the week of October 15, 2001. The CA ISO is strongly committed to working with the Commission and other interested parties to develop workable solutions to the many and varied issues discussed at the Commission's workshop. The CA ISO supports the creation of Regional Transmission Organizations (RTOs) capable of facilitating the development of deep and liquid regional energy markets and ensuring reliable system operation. Moreover, the CA ISO believes that RTOs must be adaptable, both from an organizational perspective as well as from a markets and systems perspective, to changes in the electric market. The CA ISO believes that the Commission must specify and create a foundation for further RTO development to be realized. Such foundation must be based on sound operational and economic principles, yet should provide for regional variation and innovation. The CA ISO supports the Commission's efforts, including this workshop, to develop such a foundation and looks forward to participating in the collaborative process to follow.

The CA ISO has structured its comments to address the issues discussed at each of panels that comprised the Commission's workshop.

Mandatory RTO Markets

The CA ISO believes that an RTO must define and oversee the operation of three types of markets across several time frames: a real time market for imbalance energy, adequate reserves, including ancillary services and installed capacity, and a market for allocating scarce transmission capacity (congestion management).[1] An RTO must define and oversee a real time imbalance energy market in order to balance the system in real time and maintain the reliability of the transmission system. An RTO must also define and oversee markets for

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[1] The CA ISO considers that an RTO could be either a single control area, or could be comprised of several different control areas operating in a coordinated manner subject to consistent market rules. The CA ISO believes that, so long as there is an overarching governance system that provides for compatible regional markets and coordinated operations, different approaches are possible in terms of the roles of entities that comprise the RTO as to physical operation of the system and even operation of coordinated markets, or sub-markets.

operating reserves (spinning and non-spinning reserves and regulation service), with the ability for participants to self-provide such services, and should provide for adequate installed capacity in the longer term. In addition, an RTO must define and oversee a "market" for allocating limited transmission, both in the forward and real time markets.

The CA ISO believes that these markets must be well-coordinated (across markets and across time-frames) and function to collectively provide accurate and meaningful price signals; the price signals necessary to ensure short-term and long-term efficiency through an appropriate balance between demand response, effective system operation and investment in generation and transmission facilities.

The Imbalance Energy Market and Real-time Congestion Management

The CA ISO believes that the provision of real-time imbalance energy and congestion management must be, and is, a highly coordinated function. The real-time operating requirements of an RTO are such that all real-time operation decisions and actions must be highly coordinated if they are to result in reliable system operation. Thus, the CA ISO believes that these functions must be performed simultaneously through a bid-based optimal dispatch program.

For purposes of real-time operation and congestion management, an RTO must develop and deploy an operational model based on a full or detailed network model of its transmission system; a model that accurately represents all significant, or potentially significant, transmission constraints (including, if possible, a representation of external systems). Such a full network model is necessary to reliably operate the system in real time, since real-time reliability requirements are often location-specific and require the dispatch or control of specific generating units or other resources at specific locations or areas. It is therefore imperative that an RTO employ a detailed network model in real-time operation and that the RTO publish location-specific prices that can inform and impact the actions of market participants in real time.

Importantly, a necessary feature of this market must be the RTO's ability to mitigate anti-competitive location-specific bids. Market Participants may be able to predict and cause congestion at a specific location in the grid for the purpose of selling congestion relief to the RTO at a high price if they also have the only resource capable of relieving that congestion. In the proposed Amendment No. 23 to the CA ISO Tariff, the CA ISO filed for authority to call on strategic resources at a mitigated price. This proposed amendment was rejected by the Commission, which directed the CA ISO to undertake a comprehensive process to reform its approach to congestion management. The CA ISO notes that the PJM Interconnection and the NY ISO have been granted such authority, yet the CA ISO and customers in California are still exposed to excessive decremental bids.[2]

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[2] More general issues related to market power are discussed in a subsequent section of these comments.

Forward-Market Congestion Management

Forward congestion management – and more generally, the commercial framework underlying an RTO's market design – must be consistent with and support real-time operating needs.

The CA ISO believes that an RTO must operate a forward "market" for allocating constrained transmission capacity or congestion management. That is, in combination with a process for day-ahead scheduling, an RTO should assign constrained or "scarce" transmission to those market participants that place the greatest value on the use of such capacity. The CA ISO believes that such transmission market should be facilitated through the application of a bid-based, security constrained modeling system. Simply, market participants should be able to bid for the use of constrained transmission capacity and the RTO should ensure that final energy schedules are feasible and that, based on the information known at the time of day-ahead scheduling, the system could accommodate day-ahead schedules in real time. Further, the system should provide for full use of available transmission capacity, and to the maximum extent possible minimize the existence of "phantom congestion", or the reservation of transmission capacity in the forward market for real-time transactions that never materialize.

The CA ISO believes that congestion management in the forward markets should be designed to ensure reliable operation of the system in real time and should, to the greatest extent possible, provide opportunities for market participants to self-manage their activities in the forward market. Moreover, whatever model is employed by an RTO, that model should be compatible with the models of adjacent RTOs and should, to the greatest extent possible, internalize and resolve loop flow issues.

The CA ISO believes that a one-size-fits-all approach to forward-market congestion management is not preferable or necessary. For purposes of managing and pricing transmission in the forward (DA and HA) markets, the CA ISO believes that the Commission must balance the sometimes competing objectives of 1) minimizing the difference between scheduled and actual operations (generation, load, transmission flow) so as to minimize the threats to reliable power system operation in real time and 2) providing market participants with maximum flexibility in managing their transactions in the forward market. In addition, the CA ISO believes that forward market congestion management models must provide market participants the tools necessary to self-adjust to congestion and hedge against the concomitant congestion charges that result from the application of an RTOs congestion management protocols. As recognized by the many participants at the Commission's workshop, this means that an RTO must provide financial hedging instruments such as the Firm Transmission Rights (FTRs) now in place in the California market and that also exist in the PJM Interconnection and the NY ISO. In addition, as recognized by the CA ISO in its Year 2000 CMR process, an RTO must maximize the availability of these financial instruments to all market participants and must ensure that they are structured so as to make them easily traded in RTO or market-participant facilitated secondary trading markets.

As was discussed at the RTO workshop, the CA ISO does not believe that it is possible to issue both flowgate rights (FGRs) and point-to-point FTRs in the same RTO market. Moreover, the CA ISO does not believe it is necessary to issue both products, as flowgate rights can be combined or purchased in a manner to obtain a financial hedge comparable to that of point-to-point FTRs.

Finally, while much of the discussion at the Commission's workshop (and over the past several years) has surrounded the differences between and effectiveness of "nodal", "zonal" and "flowgate" pricing models (each embodying a different level of granularity of locational marginal pricing (LMP)), the CA ISO believes that each can be effective if grounded in the requirements of actual system operation – the goal, after all, is to ensure reliable real-time operation of the system. As the CA ISO concluded in its Congestion Management Reform (CMR) process in 2000, real-time system operation and congestion management require that a system operator employ a detailed, accurate network model of its system, combined with a fairly granular (perhaps nodal) pricing model, so as to provide financial incentives for and ensure reliable system operation. In contrast, the CA ISO believes that a simpler "commercial" model can be utilized in the forward market as long as the network simplification does not mask significant congestion and lead to the inappropriate socialization of significant congestion-related costs. In other words, the CA ISO does not believe it is necessary to prescribe the use of the same pricing model in both the real time and forward markets, reflecting the fact that the reliability/operational requirements of real time are different than those of the forward markets. Perhaps even more importantly, the operating and market information available to both the system operator and market participants is different in the forward markets than it is in real time. The CA ISO believes that market participants should be provided the opportunity to self-manage their activities, including adjusting to congestion, in the forward market to the greatest extent possible.

Ancillary Services and Capacity Requirements

Ancillary Service Markets

Consistent with the Commission's statement in Order No. 2000, the CA ISO believes that an RTO must serve as the provider of last resort for all necessary ancillary services. The CA ISO supports the supposition that the provision of ancillary services is a necessary component of providing non-discriminatory transmission service and that such services should be offered under an RTO tariff.

Specifically, the CA ISO believes that an RTO must stand ready to provide the operating reserves (spinning and non-spinning) necessary to comply with established operating reserve standards and should also stand ready to provide regulation service to ensure that the system is balanced (load and generation) on a real-time basis. As described further in the next section, the CA ISO also supports the development and provision of additional “voluntary” ancillary services, such voltage support and black start service.

The CA ISO supports the Commission’s statements in Order No. 2000 that an RTO can fulfill its ancillary service obligations through a variety of mechanisms. For example, as stated by the Commission, an RTO could enter into contractual arrangements that provide for direct or indirect control of specified resources or an RTO could facilitate markets for these services. In fact, the CA ISO has availed itself of both of those methods. The CA ISO facilitates formal markets for spinning, non-spinning and replacement reserves and also for regulation service. As detailed below, the CA ISO also procures, through contract, local area reliability services (Reliability Must Run Generation); services that are necessary to support specific locational reliability requirements of the CA ISO. The CA ISO believes that both methods are viable approaches to procuring these services. The CA ISO believes that the key distinction between these methods is whether there are competitive markets for these services or whether these services must be procured on another basis. For example, the CA ISO believes that, in most circumstances, competitive markets exist for the provision of operating reserves and regulation service. However, the CA ISO believes that, because of the locational nature of the services, there are not competitive markets for local reliability services and thus these services must be procured through other least-cost mechanisms. For example, as with the CA ISO’s Local Area Reliability Services (LARS) process, the CA ISO believes that competitive solicitations can be an effective method to procure discreet services. The CA ISO suggests, however, that such solicitations be conducted for and over a timeframe that facilitates competition for providing such services. For example, the CA ISO solicits LARS a year in advance of when the CA ISO anticipates needing the service. The CA ISO also conducts its solicitations so as to provide market participants with adequate time to respond, hopefully facilitating entry of demand or alternative technology-based proposals. The CA ISO recognizes that, even then, it need to further enhance its approach so as to provide even more lead-time for such projects. The CA ISO believes that the Commission should continue to support a flexible approach to the procurement of these necessary services.

Single Versus Multi-Part Ancillary Service Bid Evaluation

At the RTO Workshop, the Commission raised the question as to appropriate pricing for ancillary services. While there was little discussion of the issue at the workshop, the CA ISO believes that the Commission raised a pertinent issue on which, at some point, the Commission must opine. Among many, one feature of the CA ISO’s markets that makes it distinct from the markets facilitated by the Eastern ISOs is the method for procuring and pricing ancillary services. Whereas the Eastern ISOs simultaneously procure energy and needed ancillary services, the CA ISO procures ancillary services sequentially and separate from energy. This difference gives rise to a pricing methodology that is separate and distinct from the Eastern ISOs. The CA ISO believes that such pricing differences are appropriate based on the basic structural design differences between the various ISOs and that, absent a mandate to change the basic design features of each market, the Commission should continue to permit different pricing mechanisms.

The CA ISO currently selects units to provide ancillary service capacity using a single-part bid evaluation approach, which awards capacity directly based on capacity bid prices. Under the two-part bid evaluation approach proposed as part of the CA ISO's initial tariff filing, ancillary service capacity bids were to be evaluated based on the Total Bid price, i.e., the sum of two components: the capacity bid price, plus an energy price component, derived by multiplying each unit's energy bid price by a factor representing the estimated percentage of ancillary service capacity that would be dispatched to provide real-time energy. Under this approach, it was proposed that each bidder selected to provide ancillary service capacity be paid a capacity payment equal to the highest Total Bid accepted by the CA ISO minus the energy component used in evaluating each unit's Total Bid. The proposed two-part bid approach also called for units providing ancillary service capacity to be paid their energy bid price (rather than the real-time imbalance price) when dispatched by the CA ISO to provide real-time imbalance energy.

The CA ISO's current single-part bid evaluation approach was adopted based on an analysis showing that this approach would result in lower overall costs than the two-part approach. In its October 30, 1997 Order, the Commission approved the use of the single-part approach, but requested a study "that explores the issue of bid evaluation further," after allowing "the CA ISO and market participants to gain experience and data under the proposed method." The CA ISO filed such a report on December 1, 1999 (**Attachment A**). The key findings of that report were that:

- The single-part approach is more efficient and results in lower overall costs due to the significant supply of supplemental energy in the real time energy market during most hours. Since suppliers of A/S capacity must compete against this supply of supplemental energy in the real time market, units selected to provide A/S capacity have an incentive to submit competitive energy bids under the single-part approach.
- While the single-part bid approach provides incentives for bidders to bid close to their actual incremental costs, the two-part bid approach would create incentives for suppliers to modify their bidding behavior to be less reflective of actual costs. Under the two-part approach, units with a high probability of being dispatched would have an incentive to increase their energy bid prices, since they would be paid their bid price rather than the market clearing price for imbalance energy. At the same time, units with a low probability of being dispatched could increase their capacity payment under the two-part bid approach by decreasing their energy bid price. Thus, compared to the single-part approach, the two-part approach would result in less efficient dispatch and higher overall A/S capacity and energy payments.

- The specific algorithm considered for the two-part bid evaluation approach is not guaranteed to minimize total capacity and energy costs. This is because this algorithm would weight each unit's energy bid by the same factor, although units are actually dispatched in merit order based on their energy bid price.

Finally, the CA ISO's December 1, 1999 study identified a variety of factors and outstanding issues that would make the two-part approach highly problematic to implement.

As noted at the beginning of this discussion, the different pricing mechanisms employed by the existing ISOs are a result of the different designs of their markets. The CA ISO believes that the Commission should continue to permit different approaches to pricing for ancillary services, especially when those differences are grounded in, and the result of, fundamental design differences between the markets.

Capacity Requirements

As evidenced by the failures last year in the California electricity markets, the CA ISO believes that each RTO must ensure that adequate capacity or installed reserve margins are maintained in its area. The CA ISO believes that adequate reserves are necessary to ensure competitive market outcomes. As evidenced by the performance of the California electricity market in 2000, absent sufficient capacity in the market, even suppliers with a relatively low market share can become pivotal suppliers during certain hours. Under these conditions, there is little an RTO can do to prevent market participants from exercising market power. The CA ISO believes that an RTO (or more appropriately, load-serving entities (LSEs)) can ensure that such capacity is available by contracting with generation or load.

The CA ISO does not believe, however, that an RTO must facilitate or operate a formal Installed Capability or ICAP market in order to ensure adequate generating capacity. As stated in its Fall 2000 response to the Commission staff's market power mitigation report and most recently in its comments on Commission staff's paper on capacity reserves, the CA ISO believes that an RTO should more appropriately require each LSE in its control area to verify that it has procured resources sufficient to satisfy its own load plus a reasonable margin (e.g., 15%). By establishing an explicit reserve "requirement", an RTO can 1) ensure that there is sufficient capacity on the system to satisfy both reliability and market requirements; 2) create opportunities for suppliers to enter into forward-contracts with LSEs and ensure recovery of their fixed costs; and 3) provide incentives for the development of load-based alternatives to generation in order to satisfy the reserve requirement (e.g., an LSE could contract with a certain percentage of load to curtail under certain defined conditions).

As explained further in a subsequent section, the CA ISO does not believe that an RTO must operate a formal DA energy market. However, the CA ISO does believe that some form of process must be in place to ensure feasible DA schedules and that sufficient resources are committed and available to serve forecasted load – all necessary conditions to ensure reliable system operation and workably competitive markets.

Voluntary RTO Markets

Energy Scheduling Markets

At this juncture, the CA ISO does not believe that the Commission should require that RTOs facilitate a DA energy market. The CA ISO believes that such markets can be developed and facilitated by market participants or other interested parties. However, the CA ISO does recognize, as informed by its own experiences, that a formal DA energy market is an extremely useful tool to enable load-serving entities and other market participants to fine tune their purchases in order to satisfy their requirements. Since the dissolution of the California Power Exchange (PX), the CA ISO has experienced an increase in block scheduling of resources that are not "shaped" to accurately satisfy each Market Participant's hourly fluctuations in load. (Of course, this presumes that LSEs accurately represent and schedule their load). The increase in block scheduling, combined with no ability for market participants to fine-tune their purchases in a DA energy market, has combined to result in, for certain hours, extreme ramps from one hour to the next. In addition, the CA ISO has been faced with the need, in some hours, to decrease or decrement resources in order to "make room" for block-scheduled resources, the sum total of which exceeds system load requirements. The CA ISO's ability to manage these extreme ramps has at times been severely challenged, resulting in short periods where frequency fluctuates to unreliable levels. The CA ISO believes that these circumstances are in part a consequence of no longer having the PX available as a "last chance" energy market for Market Participants. Thus, while the CA ISO does not recommend that such a market be mandated, there are clear benefits to having such a market in place. One such benefit, as discussed above, is a process to ensure feasible DA schedules and that sufficient resources are committed and available to serve forecasted load.

Unit Commitment

Furthermore, it has become apparent that a forward-market unit commitment process is a necessary feature of a properly functioning market. Such a unit commitment process does not necessarily mean that the RTO must centrally commit and dispatch all necessary resources. For example, under the PX, market participants self-committed their own resources. That is, once selected (based on their bid) in the PX's single clearing price auction to provide energy the next trading day, a market participant would then identify and self-commit, in the DA process, the resources necessary to satisfy its obligation. Alternatively, in the Eastern ISOs, the ISO centrally commits and dispatches resources in economic merit order to satisfy the ISO's energy and ancillary service requirements based on an optimization of each resources start-up, no-load and marginal running costs, considering transmission constraints. Under this approach, Market Participants can elect to make themselves available for central dispatch by the ISO or can choose to self-schedule. To the extent that they make their resources available for dispatch by the ISO, they are entitled to receive an uplift payment equal to their start-up and no-load costs. Thus, most resources (except those whose operation is constrained by other factors, such as environmental limitations) have an incentive to make themselves available for dispatch by the ISO. However, under either a centralized or decentralized unit commitment process, the system operator is aware of the resources committed to satisfy forecast load the next trading day. The CA ISO believes that this is an essential feature of any market; a feature or function that is necessary to ensure reliable system operation.

Black Start and Voltage Support Ancillary Services Markets

The CA ISO believes that an RTO may want to consider facilitating markets for Black Start and Voltage Support services. Currently, the CA ISO procures such necessary services under the Reliability Must-Run (RMR) contracts that it currently has in place with certain select generating units in the state. As described further below, the CA ISO has promoted competitive procurement of voltage support service its annual Local Area Reliability Services initiative. However, in light of technological innovation taking place in the industry and the availability of such new technologies, the CA ISO recognizes that Black Start, Voltage Support and other discrete requirements of reliable system operation could be provided by alternative, unconventional resources. Innovative pricing proposals will have to be developed to accurately and appropriately price such proposals and the CA ISO believes that the Commission should signal a willingness to entertain such proposals and remain flexible as to new or alternative pricing concepts.

Local Area Reliability Services

Beginning in 1998, the CA ISO launched an innovative initiative to procure necessary local area reliability services (such as voltage support) from alternative resources. As further detailed in **Attachment B**, the CA ISO's Local Area Reliability Services (LARS) initiative requested proposals from generation, transmission and load-based projects to provide certain identified services and satisfy certain local area reliability requirements. The CA ISO has conducted this so-called LARS process every year since 1998 in the hope of procuring the necessary services at least cost. Although the CA ISO has not awarded or entered into any contracts with load-based projects, the CA ISO has been successful in identifying lower cost transmission project alternatives to RMR generation. The CA ISO believes that its LARS process and the experiences gleaned from it have provided a valuable foundation of information to conduct similar solicitations in the future, perhaps for services yet to be identified. Moreover, as further explained in the transmission planning and expansion section of these comments, the CA ISO has already extended this concept of competitive solicitations for services over to its transmission planning and expansion process.

Congestion Management and Transmission Rights

The CA ISO's general thoughts regarding congestion management and the provision of transmission rights are outlined above. However, the CA ISO would like to reiterate that the Commission should remain flexible and permit individual RTOs to adopt congestion management protocols that are adapted to the situation in their respective areas. The CA ISO does believe, however, that the Commission must adopt and require adherence to certain principles for effective congestion management. That is, the Commission must ensure that the congestion management protocols ultimately adopted by each RTO are consistent with, and further, real-time operating requirements. To that end, each RTO's congestion management protocols must ensure that forward-market schedules are feasible, both with respect to forecasted load requirements and the individual operating characteristics of discrete generation resources.

As further explained in the CA ISO's January 26, 2001 CMR Draft Proposal,[3] the configurations of bulk power transmission systems vary from region to region across the United States. These varying configurations (i.e., topography of the electric systems) give rise to unique operating requirements and practices in each area. As noted in the CA ISO's draft proposal, the CA ISO

> *...must structure markets (real time and forward) around the operational requirements of the bulk power transmission system in California and its impacts on neighboring control areas, with a view to seamless operation in the broader context of a Western RTO or possibly multiple Western RTOs.*

The high voltage transmission system in California and the West spans thousands of miles to connect dispersed generation to load centers, and thus is not heavily meshed throughout the western states. This is in sharp contrast to the Eastern Interconnection, with an abundance of tightly meshed and interwoven transmission and distribution networks. This fundamental difference in network structure gives rise to unique operating requirements that must be incorporated in the market structure of an RTO if that RTO is to satisfy the basic design objective of reliable system operation.

In the daily operation of any power system, overall system security as well as local reliability requirements are determined so as to guard against thermal overloads, voltage violations, angular instability, and voltage instability in the event of credible contingencies. In comparing California and the west to the eastern network systems, the key operational distinction is that the Eastern systems are predominantly constrained by thermal limits, whereas systems in the West are constrained more often by a combination of thermal limits, angular stability, and voltage security limits.

Since it is a difficult and lengthy process to determine the exact system requirements under differing system conditions, Western operators compile

[3] The January 26, 2001 CMR Draft Proposal can be found at: http://www.caiso.com/clientserv/congestionreform.html.

operating procedures and nomograms[4] to guide real-time operations. These operating procedures and nomograms are developed using off-line studies that model different system conditions to determine the secure operating limits under each condition. The CA ISO has, however, launched an initiative to determine, based on the availability of new technologies, how to translate operating nomograms into software programs that could be utilized by dispatchers in real time.

Nomograms typically define a region of reliable operating conditions relating two or more interdependent quantities such as area generation, area load, and transmission interface flows into an area. Nomograms are developed for conditions with all transmission equipment in service, as well as conditions with equipment out of service. In addition, Nomograms can be classified into two major groups: area nomograms, which relate in-area load and generation, and transmission nomograms, which relate energy flows over two or more transmission interfaces. The nomograms are used by system operators to ensure that they operate within reliable and safe operating regions of the nomograms at all times.

The use and application of area and transmission nomograms for reliable system operation in the West lends itself to the development and application of area-specific pricing models. In theory, since all generation within an area defined by an area nomogram is equally effective at responding to changes in conditions within the area, the value of that generation to the system operator is the same. Thus, in this instance, all generation within the area should be priced or paid the same. In contrast, in the East, where operators need be more concerned about the operation of individual transmission elements, specific generators or resources at specific locations may be needed to address operating and reliability requirements. Therefore, in the East, more granular pricing may be appropriate. This is not to say, however, that these circumstances always exist in the West or East. Therefore, it is necessary to perform a case-by-case analysis to determine the required granularity of pricing. A zonal pricing scheme may be appropriate in one area of California and the West and nodal pricing in another. The Commission should not require the application of one pricing model. While much has been made of the attributes and failings of the nodal, zonal and flowgate pricing models, one truth is self-evident, market participants want flexibility and the Commission (and system operators) should accommodate such flexibility subject to the constraints of system operating requirements. To its credit, the PJM Interconnection has already attempted to provide such pricing flexibility by enabling market participants to trade in the financial forward markets based on the prices at either specific buses or nodes or larger aggregated trading "hubs". The Commission should permit each RTO to develop pricing schemes that are appropriate for their region; pricing schemes that are consistent with their operating practices and that accommodate market participant desires

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[4] Nomograms are graphs that express simultaneous relationships between generation levels, load levels, and transmission capacities, and use these relationships to identify combinations of these variables that are "safe" and "unsafe" from a reliability point of view.

for pricing certainty and flexibility. The CA ISO is currently engaged in, and is committed to, activities to ensure that, even with regional or sub-region differences, seams issues are minimized and that the RTOs models are compatible.

Transmission Planning and Expansion

The CA ISO supports the development of transmission planning and expansion principles that:

- *support development of a robust transmission system capable of supporting competitive regional markets (i.e., a robust "interstate" transmission system); and*
- *where appropriate, consider viable non-wires alternatives to proposed and needed local transmission projects.*

As recognized by the Commission in Order No. 2000, effective congestion management protocols are necessary but not sufficient in ensuring that the transmission system is expanded in a manner that facilitates the development of competitive regional energy markets. Transmission planning and expansion and congestion management protocols must work together to achieve that goal.

The CA ISO believes that it has much value to add to the discussion on the transmission planning and expansion issue. The CA ISO's coordinated transmission planning and expansion process has been an effective process that has led to the approval of almost $1 billion in new transmission infrastructure. Moreover, the CA ISO has initiated certain pilot projects to evaluate non-transmission alternatives to proposed transmission projects.

While the planning process at the CA ISO has been a significant success, better coordination with the California Public Utilities Commission (CPUC) is necessary to ensure consistent and timely permitting of transmission facilities approved by the CA ISO and to strike an appropriate balance with regard to the delineation of responsibilities in the planning and siting processes. The CA ISO is committed to resolving this most critical of issues. In addition, the planning process would be enhanced by a stronger ability on the part of the CA ISO to ensure timely construction of the projects it approves.

In addition, and perhaps most importantly, the CA ISO is in the process of developing a detailed methodology to assess the economic benefits of transmission projects that cannot be justified solely on reliability grounds. Recently, the CA ISO filed testimony in the CPUC proceeding for siting of an expansion of Path15, the major transmission interface between Southern and Northern California. For the first time since it was established, the CA ISO assessed the need for the expansion based on economic or market-related grounds. The CA ISO is undertaking a collaborative process with the Transmission Owners and relevant California state agencies to develop a methodology for the evaluation of the economic benefits of transmission projects, that builds on the work undertaken in the assessment of Path 15. Thus, the CA

ISO believes that it has pertinent hands-on experience regarding many of the issues raised and discussed at the Commission's workshop.

The CA ISO Coordinated Grid Planning Process

Much of the discussion at the Commission's workshop and specifically the discussion on transmission planning regarded the role of the RTO and market participants in transmission planning. The CA ISO strongly believes that transmission planning activities must be coordinated by the RTO. This does not mean that the RTO must do "central" planning. The CA ISO's coordinated planning process is predicated on the development of PTO-specific annual transmission plans that are developed as part of an open and public process. During that process, market participants are also invited to step forward and sponsor transmission projects that they wish to include in the applicable PTO's annual plan. The CA ISO's primary role is to oversee and coordinate the development of the PTOs' annual transmission plans and to develop, based on those plans, an integrated transmission plan for the entire ISO Controlled Grid. The CA ISO's process has been remarkably successful (stakeholders have almost unanimously praised the planning process) and we believe that such a process can be the foundation of any RTO's transmission planning process.

The CA ISO Tariff provides that the CA ISO, Participating TOs, or a market participant can establish the "need" for a transmission project on the grounds of "reliability" or "economics". The need for a transmission project must be clearly established in the CA ISO's process if the project is to be approved and supported by the CA ISO for inclusion in the Access Charge. The Participating TOs in California have an obligation to plan their respective transmission systems so as to reliably serve the load in their service areas. Thus, the primary focus of their annual transmission plans is on identifying and planning those transmission projects necessary to maintain reliable service.

Since inception, the CA ISO anticipated that "economic" transmission projects would be supported by either load-serving entities that wished to obtain access to new or alternative suppliers or suppliers that desired access to certain markets. An important matter for the Commission to consider is the role of an RTO in sponsoring and justifying the need for transmission projects necessary to support the proper functioning of regional markets. Although there was much discussion at the Commission's workshop regarding the establishment of effective price signals and relying on the market to sponsor transmission investment, the CA ISO believes that there is a legitimate "backstop" role for RTOs in furthering transmission expansion, especially when expansion may not be in the best interests of individual market participants.

Consistent with that notion, the CA ISO believes that the Commission should, to the extent possible, empower RTOs with the necessary authority and oversight powers to ensure that transmission projects identified by the RTO as needed are developed and built in a timely manner by their member TOs. While the transmission planning and approval process before the CA ISO has been largely successful, construction of needed projects has not always been adequately prompt. In addition, the role of RTOs in transmission planning, and of state agencies in transmission siting, must be coordinated. Further comments on coordination with state agencies are set forth below in the section on the Meeting with State Commissioners.

Competitive Solicitations – The CA ISO's Tri-Valley Experience

There was much discussion at the Commission's RTO Workshop regarding the role of an RTO in transmission planning and whether an RTO should have a bias towards building the transmission necessary to support a competitive market or whether an RTO should focus on developing a least-cost plan that includes "non-wires" alternatives to transmission, such as generation and load-based projects. The CA ISO has direct and pertinent experience on this matter.

Beginning in the Fall of 1998, the CA ISO began to seriously examine whether it should formally incorporate a competitive solicitation for non-wires alternatives to proposed transmission projects in its grid planning process. In part motivated by the CA ISO's interest is seeking cost-effective solutions to grid constraints, the CA ISO began to develop a formal process for conducting competitive solicitations for non-wires alternatives. This process culminated in the filing of Amendment No. 24 to the CA ISO Tariff (**Attachment C**). However, due to stakeholder concerns with aspects of the filing, the CA ISO withdrew Amendment No. 24 from consideration at the Commission. Despite the fact that the CA ISO has yet to re-file with the Commission a revised grid planning process, the CA ISO believes that it gained invaluable experience from the discussions surrounding the development of Amendment 24. Based on the concepts developed in the context of Amendment No. 24, the CA ISO embarked on the pilot-project initiative designed to test the viability of undertaking competitive solicitations for non-wires alternatives to proposed transmission projects. Working with Pacific Gas and Electric Company (PG&E), the CA ISO sought alternatives to PG&E's proposed Tri-Valley transmission project. PG&E's Tri-Valley project was a proposed 230 kV transmission line that, as proposed, would run through certain residential areas. PG&E and the CA ISO concluded that a project was needed to reliably serve load in the area. **Attachment D** contains a series of CA ISO Governing Board materials and the CA ISO's Tri-Valley Request For Proposals (RFP) that further explain the CA ISO's Tri-Valley initiative.

In addition, although the CA ISO never proceeded with the initiative, the CA ISO also explored the possibility of a non-wires competitive solicitation for San Diego Gas & Electric Company's (SDG&E's) proposed Valley-Rainbow transmission project. **Attachment E** contains CA ISO documents that further detail the Valley-Rainbow project and explain why the CA ISO ultimately decided not to proceed with the solicitation.

The CA ISO offers the following observations from its experience in developing and undertaking competitive solicitations:

Deferral vs Displacement

Perhaps the most critical issue raised in the context of the CA ISO's competitive solicitation experiences is whether non-wires alternatives can, or should be deemed to, fully displace (permanently defer) or just defer for a specified time the need for transmission. This becomes a critical issue when evaluating the bids received from potential non-wires projects and when considering appropriate compensation for such projects. For example, in the Tri-Valley RFP, the CA ISO made an up-front determination that non-wires projects would only defer the need for transmission for five years. After five years, the CA ISO concluded that load growth and other factors would require transmission expansion in the Tri-Valley area. Thus, as a result of that determination, the implicit "value" of any non-wires project would be the time-value of money of deferring the transmission project. Under this approach, assuming a twenty-percent carrying charge, the value of deferring a $100 million transmission project for five years would be $100 million. Based on that pre-determined value, respondents to the Tri-Valley RFP were constrained as to the value of their bids. This issue is further discussed in the attached material.

The "deferral" methodology clearly biases the results of such solicitations in favor of transmission expansion. However, setting aside the cost-comparison issue, there are many qualitative differences between transmission, generation and load-based projects. For example, transmission projects provide system operators with enhanced operational flexibility and by increasing transfer capability can facilitate more effective competition by providing load with greater access to more suppliers. Generation and load-based projects, if available when needed, can be used to maintain reliability and can avoid or defer, in part, the impacts on communities and the environment from transmission projects. However, strategically sited generation projects, in particular, can give rise to local market power concerns.

The Need For and Details of Performance Contracts

The CA ISO has concluded that, in order to ensure that a non-wires project will be and remain available to satisfy the reliability requirements for which it was selected, it must be subject to a legal obligation to respond to CA ISO dispatch notices at a specified mitigated price through some form of performance contract or other mechanism. That is, in order to ensure that these projects are available for dispatch, these projects must be legally obligated to perform as directed by the CA ISO. In the Tri-Valley context, the CA ISO developed a *pro forma* non-wires performance contract, included in **Attachment D**. The difficulties the CA ISO experienced in developing the *pro forma* agreement were how to structure the contract with the appropriate incentives/penalties for non-performance, the term of the contract, and cost-recovery of contract costs. As shown in the Tri-Valley contract, the CA ISO believes that it struck an appropriate balance between incentives and penalties in the performance contract. As originally proposed, the term of the contract was five years – the length of the deferral period. However, tying the length of the contract to the deferral period raised the question as to whether there would need to be contract renewal rights and the terms of that renewal. The CA ISO had concerns about the ability of a project owner to exercise market power when negotiating an extension – in circumstances where the CA ISO was dependent upon that project to provide critical reliability services.

When developing the Tri-Valley contract, the CA ISO had to address the fundamental issue of whether the CA ISO should appropriately be entering into new forms of long-term contracts with generators, especially a large number of generators interspersed throughout the grid. This issue surfaced again in the context of the Valley Rainbow project, where the CA ISO began considering whether the existing RMR contract could be used in lieu of a new form of *pro forma* agreement.

Whether a new form of contract is needed, or existing mechanisms can be used, it is likely that an RTO will require the ability to call on a unit when needed at mitigated prices if that unit is used to displace a needed transmission expansion project. However, even when relying upon the use of *pro forma* agreements, the administrative burden from administrating those contracts can be great and could further detract from an RTO's primary mission – that of providing open and non-discriminatory transmission service and ensuring reliable grid operation.

In the context of the Tri-Valley contract, the CA ISO also had to address the difficult issue on contract cost recovery. The CA ISO concluded that, since the CA ISO was seeking viable alternatives to proposed transmission projects, the costs of any non-wires projects should be recovered from the Participating TO in whose service area the project is located. The CA ISO therefore structured the billing and payment terms of the contract similar to those already in place for RMR Contracts, whose costs are also paid by the Participating TOs. While there appeared to be consensus at the Commission's workshop that generation, load or transmission-related costs should not be bundled in any manner, the CA ISO believes that the Commission should be flexible to innovative approaches to both procuring and pricing necessary grid services.

Conclusions

In summary, the CA ISO believes that an important issue for the Commission to consider and, perhaps resolve, is whether an RTO should have a bias towards transmission investment or whether an RTO should be completely impartial when considering transmission, generation and load-based options for addressing reliability and other requirements. This issue was discussed at great length at the Commission's workshop. The CA ISO believes that the objective should be both. The CA ISO believes that the Commission must establish transmission planning principles that support:

1) development of a robust transmission system capable of supporting competitive regional markets (i.e., a robust "interstate" transmission system); and

2) where appropriate, consideration of viable non-wires alternatives to proposed and needed local transmission projects.

The CA ISO does not believe that these principles are mutually exclusive. Moreover, the CA ISO believes both principles will further the objective of cost-effective solutions to address identified needs, both with respect to competitive market outcomes (generation/energy) and with regard to those activities still regulated (transmission). Thus, the CA ISO believes that it is necessary for an RTO to be proactive in ensuring that the transmission system is expanded in a manner that increases access by load to available supplies.

In addition, the CA ISO believes that it is appropriate to examine cost-effective non-wires alternatives to proposed transmission projects on a selective basis. The CA ISO believes that certain transmission projects could be deferred, or possibly displaced, by non-wires alternatives. As noted above, this would require resolution of certain issues, such as the payment and legal requirements for such projects. The CA ISO believes that these issues are resolvable and that certain transmission projects, especially those at the lower or sub-transmission voltage levels, are well-situated for examination of non-wires alternatives. However, the CA ISO advocates that the Commission closely examine the need for, and prudence of, requiring RTOs to seek competitive alternatives to high-voltage transmission projects that are necessary to facilitate regional markets.

Economic Transmission Expansion - Path 15 and the CA ISO's Development of Criteria to Evaluate Economic Transmission Projects

To date, while the CA ISO has approved close to $1 billion of transmission projects, virtually all of those projects were needed for reliability purposes. Consistent with the CA ISO's Grid Planning Criteria, the CA ISO and the Participating Transmission Owners in California plan the transmission system so that they can reliably deliver energy to load in a cost-effective fashion. Until recently, no Participating TO or Market Participant had stepped forward to sponsor what the CA ISO terms an "economic" transmission project. That is, no project sponsor had stepped forward to justify the need for a project solely on the grounds that it was needed either to eliminate congestion and ensure delivery of energy to load or to increase access to alternative supply (i.e., mitigate the market power of local suppliers). As noted above, the CA ISO believes that there is a legitimate and necessary backstop role for RTOs in ensuring that the infrastructure necessary to support competitive regional markets is in place. Moreover, RTO determinations of need on economic grounds can provide the basis for incorporating the costs of transmission projects justified to support competitive regional markets into Access Charges.

Path 15 Expansion

Path 15 is a transmission interface located in the southern portion of the PG&E service area and in the middle of the CA ISO control area. The path consists of two 500kV lines: Los Banos-Gates, and Los Banos-Midway; and four 230kV lines: Gates-Panoche #1, Gates-Panoche #2, Gates-Gregg, and Gates-Mc Call. Path 15 is a major part of the Pacific Alternating Current Intertie (PACI) which was built to facilitate seasonal exchanges between California and the Pacific Northwest as well as to reinforce the ability to transmit energy between Northern and Southern California. The majority of the flow of power from Southern California to Northern California and to the Pacific Northwest flows over Path 15; the remaining small percentage (unscheduled flow) goes through Arizona, Nevada, Utah and Idaho. The south-to-north limit on the path is 3750 MW.

Historically, Path 15 has played a major role in the seasonal exchanges that take place between Northern and Southern California, and California and the Pacific Northwest. The majority of thermal generation is located in Southern California (and the desert Southwest), whereas the majority of the hydroelectric facilities are located in Northern California and Pacific Northwest. In large part driven by this geographic dispersion of thermal and hydroelectric generation, power typically flows from the south to north over Path 15 during winter off-peak hours, in part to enable northern hydroelectric resources to restock and conserve their water supplies, thus making those critical resources available during critical peak periods. This historical use of resources (and Path 15) has held constant even after the implementation of restructuring in California. However, these historical seasonal exchanges and resultant power flows over Path 15 have often been limited by the operating capacity of Path 15. Thus, since the CA ISO began operations, Path 15 has been defined as an Inter-Zonal Interface (connecting the Congestion Zone north of Path 15 -- NP15 -- with the Congestion Zones south of Path 15 -- SP 15 and ZP26) in the CA ISO's Congestion Management process. As a result of this designation, transmission customers (Scheduling Coordinators) that submit schedules that use Path 15 must pay a charge (Usage Charge) for the right to use the constrained or "scarce" transmission capacity available on Path 15.

As a result of the persistent congestion on Path 15 and, in specific limited instances, the need to curtail Northern California load as a result of Path 15 congestion and limited Northern California and Northwest hydroelectric resources, the CPUC directed that PG&E and the CA ISO examine the viability of upgrading Path 15. As explained in the attached testimony before the CPUC (**Attachment F**), based on a careful examination of the market impacts of a Path 15 upgrade, the CA ISO determined that a Path 15 upgrade was warranted. An examination of historical Congestion costs and studies undertaken by the CA ISO indicated that: 1) between September 1, 1999 and December 31, 2000, Congestion on Path 15 cost California electricity consumers up to $221.7 million; and 2) using reasonable assumptions, the $300 million cost of upgrading Path 15 could potentially be recovered within one drought year, plus three normal years.[5]

The CA ISO determined that a $300 million project to add 1500 MW of transfer capability to Path 15 was economically justified to reduce the risk of high prices. Specifically, the CA ISO determined that upgrading Path 15 would mitigate market power of strategically located generation. The CA ISO determined that a Path 15 upgrade was further supported by anticipated drought hydro conditions and uncertainty as to the availability of transmission capacity subject to Existing Contracts and as to where new generation will locate. The CA ISO determined

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[5] The CA ISO's testimony and supporting exhibits (studies) can be found at: http://www.caiso.com/docs/2001/06/12/2001061215095117712.html

that these factors would further affect the market power of strategically located generation and therefore could increase the need for proactive mitigation measures such as upgrading Path 15. Finally, the CA ISO concluded that upgrading Path 15 was consistent with a broader strategy to put into place a robust high-voltage transmission system that supports cost-effective and reliable electric service in California and a broader and deeper regional electricity market.

The CA ISO notes that on October 19, 2001, Department of Energy (DOE) Secretary Spencer Abraham announced that the DOE, in conjunction with the Western Area Power Administration and other parties, were prepared to move ahead with a Path 15 upgrade project. This announcement further validates the CA ISO's conclusion that upgrading Path 15 is in the best interest of Western consumers.

The CA ISO's Development of Criteria to Evaluate Economic Transmission Projects

On July 3, 2001, the CA ISO issued an RFP soliciting proposals for the development of "Transmission Project Evaluation and Justification Principles and Methodology Recommendations" necessary to support an economic transmission project. This effort will further develop and refine the methodology to assess the economic benefits of a transmission project pioneered in the analysis of the expansion of Path 15. As further explained in the RFP (**Attachment G**) the recommendations to be developed from the RFP:

> …are expected to provide the basis for the ISO to assess the economic benefits and justify the construction of transmission projects to expand California's access to dispersed and diverse electricity markets and resources, in order to lower the cost of electric service for California consumers.

Since May of 2000, the CA ISO and others have recognized that the high prices in the wholesale electric market and the increasing frequency of system emergencies are the result of a lack of adequate generation and transmission infrastructure. The lack of adequate generation has lead to a supply/demand imbalance that has resulted in high prices and the exercise of market power. The lack of transmission resulted in an inability to reliably deliver existing generation, prevents access to new generation, and creates locational market power for certain strategically located generation.

The CA ISO firmly believes that the development of a methodology to assess the economic benefits of transmission upgrades will lay the foundation for future transmission expansion not only in the West but across the nation. As noted earlier in these comments, the bulk of the transmission projects approved to date in California (and most likely nationwide) have been justified or needed in order to maintain the reliability of the transmission system. In the future, the CA ISO believes that an increasing percentage of the transmission projects will be needed to further support development of robust and liquid regional energy markets. Absent the development of clear and appropriate criteria for the evaluation of such projects, economic transmission upgrades may never be initiated and, more likely, will linger in a regulatory limbo as various constituencies labor over the details of and the need for the transmission projects.

The CA ISO believes that the development now of a sound economic methodology for evaluating, supporting and allocating the costs of economically-based transmission expansion will further the CA ISO's and Commission's objective of facilitating competitive electricity markets. Subsequent to the development and validation of such a methodology, market participants, financiers and regulators will have a solid foundation for developing and supporting economic transmission projects. Moreover, development of a methodology can only further enhance the ability of RTOs to play an important backstop role in the creation of a network system capable of facilitating a seamless national energy market.

Standardizing RTO Tariffs

The CA ISO supports the proposal to standardize RTO tariffs to the greatest extent possible. However, consistent with the Commission's approach in Order No. 888, the CA ISO also believes that the Commission should remain flexible and permit RTOs to vary from the Commission's standard where appropriate. As a general matter, the CA ISO recognizes that by standardizing RTO tariffs the Commission will make it easier for market participants to know and understand the rules and practices of each RTO. Moreover, the CA ISO supports such standardization to the extent that it further facilitates interregional coordination and interregional transactions. The CA ISO recognizes that for as long as there are multiple RTOs functioning within a region or interconnection, the minimization of "seams" issues will be important. However, as explained earlier in these comments, the CA ISO believes that the Commission must permit RTOs to develop tariffs that are appropriate for their regions and thus reflect the unique physical characteristics and operating requirements of their regions.

There was much discussion at the workshop regarding the need for a very flexible service, one that combines the best features of the Commission's *pro forma* tariff and the services provided thereunder: network and point-to-point service. The CA ISO believes that the service provided under the CA ISO Tariff is extremely flexible and, for the most part, serves the needs of market participants. Service under the CA ISO Tariff is generally a network type service but does not require that participants formally designate and list network resources in advance of the DA scheduling process. The CA ISO believes that such approach offers market participants maximum flexibility. While the CA ISO has identified and is identifying necessary enhancements to the CA ISO's markets and tariff necessary to ensure that the CA ISO has all of the requisite information to ensure reliable system operation, the CA ISO believes that the basic services provided under its tariff constitute a foundation for any RTO tariff.

Although the CA ISO generally believes that the services provided under its tariff are flexible, the CA ISO recognizes that market participants may desire additional services and even more flexibility. Since inception, the CA ISO has heard requests from market participants for the provision of non-firm or discounted transmission service. In response, and in order to increase and make available transmission capacity for use by market participants, the CA ISO began to develop the requirements and details of a Recallable Transmission Service (RTS). Details regarding the CA ISO's RTS proposal can be found in the January 26, 2001 CMR Draft Proposal referenced above in footnote 3 and the accompanying text. Market participants have also requested increased scheduling flexibility and the opportunity to offer discrete Voltage Support and Black Start services. The CA ISO is committed to serving the needs of its customers and stands ready to engage market participants in developing additional and more flexible services, where feasible and appropriate.

Cost-Recovery Issues

Recovery of Embedded Transmission Costs

There is no greater impediment to the formation of RTOs than the obstacles surrounding resolution of cost-recovery or cost-shifting issues associated with transmission investment. As the Commission is aware, the Pacific Northwest's previous attempt to form a regional transmission operator (INDEGO) ultimately failed because the participants were unable to solve these vexing issues. More recently, RTO West and WestConnect have been successful in moving their proposals forward because they have been able to reach consensus on cost-recovery issues. The CA ISO recommends that the Commission move carefully in this area and on issues that may impact cost recovery. The CA ISO is concerned that should the Commission attempt to establish a uniform or generic approach to resolving cost-recovery issues, the Commission could upset tenuous and delicate compromises on these issues that could break up fragile coalitions.

The CA ISO believes that the Commission should focus its attention not on establishing a "one-size fits all" approach to transmission pricing, but should instead focus on reducing or eliminating seams issues between RTOs. Recognizing that the CA ISO, RTO West and WestConnect have all negotiated individually tailored solutions to their transmission cost-recovery/cost-shifting issues, the three entities are now working to further interregional coordination efforts and eliminate seams issues. The Commission should support such an approach, as it is the surest way to satisfy its primary goals: the creation of RTOs and the development of seamless regional energy markets.

Generator Interconnection Costs

Participants at the Commission's workshop discussed at great length the issues surrounding generator interconnection costs. The CA ISO agrees that this is a critical issue and one on which the Commission must establish a clear and internally consistent position. Absent the development of a clear policy on this issue, the development of new generation may be delayed or abandoned.

Developers of new generation prize price certainty, and the Commission should move to quickly establish policies that provide, to the maximum extent possible, such certainty. However, the CA ISO does not support the “just build transmission option” to further generation development. The decisions of generation developers must in part be guided by the cost-consequence of their actions. Building transmission to completely eliminate “barriers” to new generation will result in overbuilding and inefficient expansion of the system.

The CA ISO believes that the Commission must strike an appropriate balance between eliminating barriers to entry for new generators and sending such generators accurate and appropriate price signals regarding their investment and location decisions. The CA ISO strongly believes that it achieved such a balance in its proposed Amendment No. 39 to the CA ISO Tariff. (Amendment No. 39 was filed on April 2, 2001, in compliance with the Commission’s December 15 order regarding matters in the California electricity market. As of this date, the Commission has not acted on the CA ISO’s filing). In Amendment No. 39 the CA ISO, as well as its Participating TOs, proposed that new generators be responsible for the cost of direct interconnection costs (e.g., generation tie lines and other costs up to the first point of interconnection with the grid) and reliability upgrades, such as breakers, even if those facilities were located beyond the first point of interconnection. The CA ISO proposed that new generators not be responsible for the cost of “voluntary upgrades” or upgrades necessary to deliver the facility’s output to load. The CA ISO reasoned that new generators could and should make the decision whether to rely on the CA ISO’s congestion management protocols (i.e., pay for the use of constrained transmission capacity based on whatever value they place on that use) or fund the necessary upgrades necessary to ensure that they can deliver their output to load. While the CA ISO recognizes that the exigent circumstances in California may necessitate the rolling-in of these expansions in the near term in order to expedite the addition of new generation in the capacity-starved West (as contemplated in the Commission’s series of “Orders Removing Obstacles in the West”), on a long-term basis the CA ISO believes that market participants should face and make these decisions, and the financial consequences, based on the specifics of their own projects and circumstances.

In the end, the CA ISO believes that the Commission must marry the policies on new generator interconnection and transmission expansion. As explained above, the CA ISO does believe that there are circumstances where an RTO should direct expansion of the system (or have the ability to itself expand the system) in order to further establishment of competitive regional markets (i.e., remove transmission constraints so that customers have access to more suppliers and so that suppliers can access other markets, thus reducing market power of strategically located suppliers). The CA ISO urges the Commission to move quickly to establish internally consistent policies on these issues and strike a delicate balance between sending appropriate price signals to new generation and furthering the development of robust regional transmission systems.

Municipal and Government Entity Participation in RTOs – Maximizing Available Capacity

Cost-shifting or cost-recovery issues (as well as others) have been cited by many participants as a primary reason why municipal and governmental entities have not joined existing ISOs or proposed RTOs. FERC jurisdictional transmission owners have raised concerns that municipal facilities are generally high-cost (because they are newer) and that if municipals were to join an RTO, other transmission owners customers would be required to pay for these higher cost facilities. The range in transmission embedded costs among California transmission owners alone is from $1.00/MWh to over $12.00/MWh. Municipal and governmental entities have raised concerns that the benefits under their existing transmission arrangements are superior to the services and benefits offered by RTO membership. While these issues are vexing and require difficult negotiation, the CA ISO believes that the Commission must proactively engage in resolving these issues. As the Commission is aware, the preservation of numerous Existing Transmission Contracts (ETCs or Existing Contracts) in California has resulted in a large amount of transmission capacity left “on the table” on a daily basis in California. That is, as explained further below, because the CA ISO cannot offer in the forward markets unused ETC capacity to other market participants, that capacity often goes unused in real time. The CA ISO urges the Commission to address this issue and to establish policies that ensure that the maximum amount of transmission capacity is made available to the market based on RTO-established scheduling timelines.

The Commission’s March 14, 2001 Order Removing Obstacles in the West correctly recognized that "eliminating bottlenecks which prevent maximum utilization of existing supply must be accomplished efficiently and expeditiously."[6] The CA ISO concurs fully with this statement. The one reform within the sole jurisdiction of the Commission that can enhance utilization of the transmission grid without the need for physical modifications is the mitigation or elimination of congestion caused by the CA ISO’s requirement to honor and reserve transmission capacity associated with ETCs under the CA ISO Tariff and previous Commission orders. Existing Contracts often contain scheduling timelines that are different from the CA ISO’s Day-Ahead and Hour-Ahead scheduling timelines and often allow scheduling up to, and into, the operating hour. In order to honor these Existing Contracts, transmission capacity is reserved in the CA ISO’s Day-Ahead and Hour-Ahead scheduling processes but often is not used by existing rights-holders. These Existing Contract reservations cause paper or so-called “phantom” congestion. While the CA ISO can use in real time any transmission capacity that has not been scheduled by existing rights-holders in the Hour-Ahead scheduling process,[7] the reserved and unused transmission capacity is not available for use by Market Participants in the CA ISO transmission markets (i.e., the Day-Ahead and Hour-Ahead scheduling processes).

[6] 94 FERC ¶ 61,272, at 61,969.
[7] *See* ISO Tariff, Section 2.4.4.5.1.6.

In its Order concerning Amendment No. 27 to the CA ISO Tariff, the Commission described the problem of phantom congestion within the CA ISO Controlled Grid:

> *This term, as explained by the ISO, relates to the scheduling timelines afforded to current G[overnmental] E[ntitie]s under Existing Rights contracts which are different and not entirely compatible with the day-ahead and hour-ahead schedules that the ISO operates under. Because the Existing Rights contracts allow scheduling changes after the ISO scheduling deadlines, available transmission capacity remains unutilized. According to the ISO, an after-the-fact review of actual data from December 1998 to November 1999 indicates that in many days the congestion on contract paths was less than anticipated because the holders of Existing Rights did not fully utilize those rights, but that information was not available in real time to the ISO to allow the market to respond. Thus, the ISO states that, if there were immediate conversion of Existing Rights to FTRs for new Participating TOs, this "Phantom Congestion" would be eliminated.*
>
> *A number of GEs argue that: (1) "Phantom Congestion" is a valuable scheduling right of the GEs; (2) the ISO is at fault for failing to develop software to accommodate these rights nor recognize the operational realities of full service utilities; and (3) the requirement that Existing Rights be converted to F[irm] T[ransmission] R[ight]s to alleviate the purported "Phantom Congestion" is a step backwards inasmuch as the ISO currently allows a five year conversion period during which time a party to an Existing Contract can become a new Participating TO and continue to exercise their contract rights. Additionally, some GEs have suggested that the appropriate place to deal with this issue may be the stakeholder process now under way in the ISO congestion management program.*

The CA ISO does not agree with the position taken by the GEs. Software that perpetuates the non-conforming schedules will not fix this problem of "Phantom Congestion." The CA ISO believes that this approach simply suggests an iterative scheduling process that will not allow sufficient time for the market to respond and will leave the CA ISO with insufficient time to manage the grid reliably. Furthermore, while GEs contend that their scheduling flexibility is a valuable asset, it results in overall market inefficiencies due to scheduling time lines that do not conform to the time lines of the overall markets. It is difficult to justify the scheduling flexibility advantage in light of the congestion these rights cause the CA ISO.[8] Additionally, because of the volume of transactions in the CA ISO's hour-ahead market, it is not a practical solution to allow that market to run closer to real time.

[8] *California Independent System Operator Corporation*, 91 FERC ¶ 61,205 at 61,727 (2000).

The Commission recognized that phantom congestion was "a market inefficiency that must be addressed and rectified as quickly as possible" and stated that, if the issue was not resolved in the overall settlement negotiations concerning that CA ISO's transmission Access Charge, the Commission would "address it in a separate proceeding."[9]

The CA ISO is pleased to announce that the parties to that proceeding are making progress. However, as a general policy matter, the CA ISO urges the Commission to establish policies that address this issue prior to, or as part of, the formation of RTOs and not permit this issue to go unresolved and become the subject of lengthy negotiations.

Meeting with State Commissioners

The state commissioners present at the Commission's workshop delivered a clear and consistent message to the Commission: "show us" the benefits of moving to and creating a few large RTOs and that the Commission must actively engage state commissions in a deliberative process if the Commission is to achieve a "seamless national energy market." The CA ISO fully supports the need for enhanced federal-state cooperation and collaboration. The CA ISO believes that the Commission and RTOs must work with states, especially those with existing low energy costs, to ensure that the long-term benefits from establishment of large regional energy markets is in the best interest of consumers in all states. Furthermore, the CA ISO believes that the Commission and state regulators must engage each other to address two areas critical to the success of RTOs:

1) The Commission must work with states to ensure an efficient and seamless transmission planning and siting process. Absent federal authority to site transmission (something not likely to be granted in the near future), states will continue to be the regulatory authority charged with siting new transmission facilities. Thus, RTOs, charged with planning the transmission system in order to ensure grid reliability and facilitating competitive markets, will need to work closely with state commissions to ensure that the necessary transmission projects get sited in an efficient and timely manner; and

2) The Commission must work with state commissioners to further the development of price-responsive demand in each state and, more broadly, each RTO's market. The development of effective end-use customer demand response programs (especially those facilitated by state-jurisdictional utilities) is clearly within the purview of state regulators.

With regard to item one, the CA ISO is attempting to work cooperatively with the CPUC to develop an efficient transmission siting process. Pursuant to the provisions of Assembly Bill 1890 (AB 1890), the CA ISO is charged with maintaining the reliability of the CA ISO Controlled Grid. Concomitant with the CA ISO's responsibility to maintain system reliability, the CA ISO is also charged with planning and directing the expansion of the CA ISO Controlled Grid so as to

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9 *Id.*

ensure a reliable and efficient transmission system. These functions and responsibilities are codified in the CA ISO Tariff. Under California statute, the CPUC is charged with overseeing the transmission siting process in California. Specifically, the CPUC is entrusted with the responsibility to ensure that proposed transmission projects are necessary and economical, considering route, impact on communities and impact on the environment.

In an ideal process, determinations of need made in the context of the CA ISO's transmission planning process would carry over and remain valid in the context of the CPUC's siting process. After a determination of need for a transmission project has been made by the CA ISO, the CPUC, in its siting process, would focus on environmental, community impact and other issues that are clearly within the CPUC's jurisdiction.

The Participating Transmission Owners, working in conjunction with the CA ISO, have already sought siting approval before the CPUC for three major transmission projects. In these cases, there has been disagreement on the respective roles of the CPUC and the CA ISO with regards to planning and determinations of need. More recently, questions have emerged as to the respective roles of the CPUC and the CA ISO regarding the determination of economic benefits of transmission projects and cost allocation. Until the respective roles of the CPUC and the CA ISO are more clearly defined, there is the potential for significant duplication of efforts, inconsistent results before the CA ISO and the CPUC, and consequently delays in project approval, permitting and construction.

The CA ISO is committed to working with the CPUC and other parties in California to ensure that necessary transmission projects are not delayed as a result of a duplicative and inefficient transmission planning and siting processes. The CA ISO urges the Commission to work cooperatively with the states to develop planning and siting processes that result in lower costs to consumers and the development of robust and efficient transmission systems.

As to the second issue, the CA ISO believes that the Commission and each RTO must work cooperatively with state regulators and policymakers to ensure the development of a critical market component – price responsive demand. While, in the end, the CA ISO advocates the tight integration and coordination of wholesale and retail electricity markets, the CA ISO believes that an invaluable interim achievement would be to ensure that at least ten percent of load is price responsive. As witnessed by the positive impact of the voluntary conservation efforts in California this past summer, even if only a portion of load is responsive to price, that may be sufficient to mitigate the market power of strategically positioned suppliers. In order to achieve this goal, the Commission must work cooperatively with state regulators to immediately expand participation in both retail and wholesale market demand response programs. Moreover, the Commission should emphasize the importance of real-time pricing initiatives and identify and support pricing proposals that support (if not subsidize) such initiatives.

The CA ISO stands ready to engage the Commission and state regulators in furthering these initiatives. The CA ISO believes that RTO input into the development in demand response programs is critical to ensure that these are consistent with, and where appropriate incorporated into, wholesale electricity markets, as well as, supportive of an effective and reliable physical operation of the system in real time.

Standardizing Markets, Business and Other Practices

The CA ISO agrees with many of the panelists at the Commission's workshop that the Commission must first clarify what it believes to be necessary or appropriate market design features before the industry can define standard business rules or practices. The CA ISO also believes that the development of such business standards and practices is best left to the industry and its participants. Consistent with that position, the CA ISO supports the movement by the Gas Industry Standards Board, the Electronic Scheduling Collaborative, and the North American Electric Reliability Council (NERC) to expand their focus and activities to include the development of electric industry business standards. However, the CA ISO believes that the Commission should support the creation of a single entity as the entity charged with developing and leading that initiative. The existence of multiple entities or institutions that develop electric industry business standards will be counterproductive and confusing. Having said that, the CA ISO urges the Commission, and whatever entity is ultimately charged with developing electric industry business standards, to recognize regional differences, especially where those differences have a possible or probable impact on the reliability of that region.

As mentioned earlier in these comments, the CA ISO is currently engaged with other Western entities to identify products and services that can be standardized or, at a minimum, made compatible, so as to ensure a seamless marketplace. The CA ISO believes that standardization across markets will facilitate inter-regional transactions. In that vein, the CA ISO is engaged in discussions with RTO West and WestConnect to identify opportunities for pricing reciprocity and for functions and services that can be standardized and perhaps procured on a West-wide basis.

Market Monitoring and Mitigation of Market Power

As presented by the CA ISO at the Commission's workshop, the CA ISO believes that the Commission should move quickly to establish clear and appropriate standards for the granting of market-based rate authority and for identifying when prices exceed just and reasonable levels. In addition, the CA ISO believes that the Commission should ensure that RTOs are able to quickly and appropriately respond to the exercise of market power or anomalous bidding behavior, either through the exercise of ex ante measures or expedited reporting procedures. Moreover, the CA ISO believes that the Commission must move to update and revise its own existing internal procedures and processes to better respond to the dynamic nature of electricity markets. Finally, the CA ISO believes that the Commission should work cooperatively with states to ensure that there is a clear delineation and understanding of federal and state jurisdictional authority. Absent such definition, regulators may waste precious time when responding to changes in the market. The CA ISO believes that market monitoring and effective market power mitigation are essential functions of an RTO. The CA ISO believes that it has shared and can share invaluable insight into these functions. As such, the CA ISO has already engaged in discussions with RTO West and WestConnect regarding a unified vision of the market monitoring for the West.

As further explained in the prepared written remarks of Dr. Anjali Sheffrin, the CA ISO's Director of the Department of Market Analysis (**Attachment H**), the main objective of market monitoring and market analysis is to detect and identify the causes of the exercise of market power, market inefficiency, and gaming. In addition, monitoring in RTO markets must determine whether transmission service is being provided on a nondiscriminatory basis and that the transmission system is being operated in a way that ensures reliability. As explained by Dr. Sheffrin in **Attachment H**, the Commission must take five key actions to achieve effective market monitoring and ensure competitive market outcomes:

1. Establish a clear standard for just and reasonable rates and formulate an effective enforcement mechanism for this standard;
2. Provide effective tools and authority to the monitoring units of the RTOs in order to mitigate the undue exercise of market power;
3. Overhaul the criterion for granting market-based rate authority to sellers;
4. Improve federal and state co-ordination on issues which may impede competitive market outcomes; and
5. Ensure that there is an adequate supply of generation.

First, the Commission should establish a clear standard for just and reasonable rates. Currently there are no clear procedure and no standards for measuring when markets are producing just and reasonable prices. As a starting point, CA ISO has offered a practical method that the Commission can adopt to evaluate market performance on a 12-month rolling basis by comparing a 12-month rolling market cost figure (actual market price times volume) to a 12-month threshold. The threshold can be set at the 12-month rolling cost-based plus 20%. Alternatively the threshold can be set at the 12-month rolling average of competitive market prices plus 10%.

When the actual 12-month rolling market costs exceed either the cost of service-based or competitive market price based threshold, the Commission should automatically intervene in the market. A clear standard for action would eliminate a concern that the Commission might intervene arbitrarily while also signaling that the Commission will not allow systematic bidding at un-competitive prices. The proposed methodology is prospective and easy to calculate. One important feature of this approach is that isolated price spikes would not mandate action, but significant deviations on a sustained basis would.

This approach could have averted much of the damage from the California power crisis in 2000. During the first two years of competition in California power markets, market costs were no more than 7 percent above an effective competitive market outcome, even though there were occasional price spikes as high as $9,999. In May of 2000, after repeated price spikes, the rolling average cost of electricity reached 10% above a competitive market outcome. Since then, the monthly deviations between the rolling average cost of electricity and a competitive market outcome have been 40% or more (see **Attachment H**). Thus, focus on 12-month rolling averages would filter out occasional price spikes but still set specific thresholds to identify unjust and unreasonable rates.

A clear standard for just and reasonable rates provides market participants certainty and information which they can use in their own planning. Consumers would know the level at which regulators would intervene to prevent market abuse. Suppliers would also be aware of the level and would have the ability to self-regulate their bidding in order to avoid regulatory intervention.

Second, the Commission should provide effective tools and authority to the RTO market monitors. Again drawing on the California experience, CA ISO market monitors (the CA ISO Department of Market Analysis and Market Surveillance Committee) developed a catalog of indices to document market performance and issued numerous reports and recommendations on how to mitigate the market power revealed by the data. However, market monitors had limited ability to enact and enforce mitigation measures. In the future, RTO market monitors must be given the tools to respond promptly when market disorders are identified.

Third, the Commission should revise its criteria for granting market-based rate authority to sellers. The California experience offers some valuable lessons as to circumstances in which sellers are able to exercise market power. Until now, the Commission has considered that sellers must have a 20 percent market share to exercise market power and inflate market prices. In fact, the 20 percent standard has been shown to be wholly inadequate. Static indices such as market share or HHI are very inadequate measures of market power in the electricity industry since electricity markets change minute by minute. Static indices cannot account for changes in the availability of generation and transmission, and most importantly do not account for fluctuations in system demand hour by hour. A seller with 20 percent market share may be unable to exercise market power when there is low demand and a large amount of generation available. But a seller with a market share as low as 5 percent can become pivotal and exercise market power when demand is more than 95 percent of the total available capacity. A better indicator of market power is suggested: a simple index that has been developed by DMA called a Residual Supply Index, which can be calculated for any season, day or hour of the market. A close correlation between RSI and price-cost mark-up has been estimated for the California markets and can be used to evaluate the potential market power for large suppliers (See **Attachment H**).

Fourth, the Commission should improve Federal and State coordination. There are many actions that are subject to the jurisdiction of state regulators that impact wholesale market performance. Some examples are the structure of retail competition, the design of demand response programs, or the requirements and limitations imposed on utility forward contracting. These factors are often critical to the competitiveness of wholesale markets. Thus, there must be better coordination between state actions and federal actions to ensure there are no undue barriers to efficient operation of wholesale markets.

Fifth, the Commission should ensure that there is adequate supply to support competitive market outcomes. Studies of reserve margins by the CA ISO indicate that adequate reserve margins contribute to the effective operation of competitive markets. Competitive outcomes are more likely when reserve margins meet or exceed 15 percent. As illustrated in **Attachment H**, a relationship between low reserve margins and price spikes has been observed in several competitive electricity markets including PJM, New York, New England, and Ontario.

The Commission has requested comments on instituting capacity requirements. CA ISO supports properly structured capacity requirements. The CA ISO supports in particular a requirement that LSEs obtain adequate reserves well in advance of real time. The LSE could meet the reserve requirement with a combination of generation, transmission, and demand side programs. To the extent that LSEs secure sufficient resources to meet load in the forward markets, price spikes can be avoided or reduced.

These five steps are not difficult. The exercise of market power in California markets persisted for 12 months without effective action. This experience destroyed a tremendous amount of confidence in the outcome of electricity deregulation. The Commission must be aggressive with regards to market monitoring and market power mitigation to regain confidence in a competitive approach to electricity regulation. One central benefit of adoption of the five steps outlined above would be to create confidence on the part of all market participants that markets will yield just and reasonable prices, and that RTO development will be beneficial to all. These actions will go a long way to making the Commission’s vision of RTOs a reality across the country.

The CA ISO looks forward to working with the Commission in further refining and defining the requirements for effective market monitoring and market power mitigation. The CA ISO requests that the Commission avail itself of the invaluable experience of the CA ISO’s market monitoring staff when addressing these matters.

Conclusion

The CA ISO once again thanks the Commission for the opportunity to provide these comments on the Commission’s RTO Workshop. The CA ISO is committed to working with the Commission and all interested parties in California and the West in furthering the development of reliable, robust and competitive regional energy markets. The CA ISO believes that it has benefited greatly from its experiences over the past three and half years and believes that the Commission can also benefit from the CA ISO’s experience. The CA ISO believes that the observations and documents that accompany these comments will greatly assist the Commission in responding to the many and varied questions and issues that were discussed at the workshop. The CA ISO looks forward to participating with the Commission and others in future discussions regarding these matters.