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 Federal Energy Regulatory Commission's "Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design"

The California Independent System Operator Corporation ("ISO") appreciates the opportunity to submit comments regarding the Federal Energy Regulatory Commission's ("Commission") "Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design" ("Options Paper") issued on April 10, 2002 in the above-referenced docket. On April 24, 2002, the ISO submitted an Answer in support of several motions that were filed requesting an extension of due date for comments on the Options Paper until May 31, 2001. The ISO indicated in its Answer that, given the number of ISO personnel dedicated to putting together the ISO's MD02 comprehensive market resign proposal, an extension of time was necessary and appropriate. On April 26, 2002, the Commission issued a "Notice Regarding Requests For Extension Of Time" in which it stated "if interested persons are unable to meet the May 1, 2002 deadline, we encourage them to file their comments as soon as possible so that they may be considered in the development of the NOPR." The ISO was unable to meet the May 1,2002 deadline because the personnel responsible for evaluating and commenting on the Options Paper were the same personnel involved with the MD02 Filing. In addition, these same personnel are involved in drafting the Tariff revisions associated with the long-term elements of the MD02 proposal, which tariff revisions will be filed in mid-June. Under these circumstances, it is appropriate that the

Commission accept the instant Comments for consideration consistent with its April 26, 2002 Notice.

As the ISO has previously noted, it supports the Commission's objective of developing a standardized wholesale market design. Such standardized market design must, out of necessity, address and resolve rate and transition issues associated with implementation of any standardized transmission service. The ISO believes that in the Options Paper the Commission has correctly enumerated the major transmission service and long-term generation adequacy issues. These issues are: (1) recovery of embedded costs of the transmission system, (2) allocation of transmission rights, (3) transition of existing contracts to the new transmission service, and (4) long-term supply adequacy. The ISO's comments will address these issues discussed in the Options Paper seriatim.

1. Current Services and Recovery of Transmission Revenue Requirements

a.) Who Pays The Access Charge

Option 1 contemplates assessing an access charge to any entity that schedules on a transmission provider's system, whether as an import, service between a receipt and delivery node on the system, or purchases of power by load from energy markets. However, as the Options Paper notes, this option may be problematic because it could result in multiple access charges being paid for the same MW if there are intermediate transactions in the process of actually delivering power to serve load.

Under the ISO's current scheduling process and the scheduling process proposed in the ISO's May 1, 2002 comprehensive market redesign filing in Docket Nos. EL00-95-001, et al.

(“MDO2 Filing”), any such intermediate transactions are “invisible” to the ISO because all schedules that utilize the ISO control area are set for delivery to load take-out points or to intertie points for export. Thus, any intermediate transactions such as trades at a trading hub between a marketer and load-serving entity (LSE) are internal to the scheduling coordinator(s). Accordingly, the ISO does not consider this option viable.

Option 2 assesses the access charge to load. The ISO agrees with the principle that only customers who take power off the grid (and not parties engaging in intermediate transactions as identified in Option 1) should be responsible for the access charge. The ISO’s present approach is similar, except that the access charge is also paid by exports from the ISO control area (including wheels through). As discussed below, the ISO recognizes the concern about the pancaking of charges and is considering, in collaboration with its counterparts in other western states, ways to resolve this issue on a regional basis.

Option 3 ties payment of an access charge to whether the customer has protection against congestion charges. In other words, the access charge could only be paid by customers offered Transmission Rights or an allocation of revenues from the sale of Transmission Rights. The ISO agrees in principle with the concept that customers who pay the access charge should be entitled to Transmission Rights or associated auction revenues. However, a methodology that explicitly links access charge payments to allocations of Transmission Rights or auction revenues would be extremely complicated and difficult to administrate accurately. This may be particularly difficult in relation to the treatment of existing transmission contracts that may have transmission rates locked in from earlier periods. Accordingly, the ISO believes that Option 2 is preferable to Option 3.

The ISO believes that the aforementioned principle can more easily be achieved by a combination of Option 2 and Option 3. Indeed, the ISO's MD02 Filing, combines Options 2 and 3 because access charges will be paid by all Loads within the ISO Control Area (as envisioned by Option 2) and, consistent with Option 3, these Loads will be given firm transmission rights in sufficient quantity to permit hedging against congestion charges that would be incurred under Locational Marginal Pricing ("LMP") in the process of procuring Energy to meet their Demand.

b.) Should The Access Charge Be Assessed To Exports Or Wheel-Through Transactions?

The Commission sets forth the following options regarding the application of access charges to exports and wheel-throughs: (1) Option 1 would levy an access charge against exports and wheel-throughs; (2) Option 2 would not levy an access charge on exports and wheel-throughs; (3) Option 3 would not charge individual transactions, but there would be an annual revenue adjustment; and (4) Option 4 would assess a lower access charge against exports and wheel-throughs as compared to deliveries within the transmission provider's system.

The ISO notes that Option 1, while compatible with the Commission's current pricing policy for exports and wheel-throughs, leads to the pancaking of charges. Option 2 eliminates pancaking of access charges, but, absent appropriate scheduling rules, can promote phantom wheeling in the counter flow direction, whereby usage charges may be collected with a net schedule of 0 MW. If no access charge is assessed on wheel-throughs, there may be no cost to discourage a market participant from submitting strategic circulating schedules that do not have a connection to an actual sink or source, thereby creating counter congestion loop flows. Such schedules would collect usage charges in the forward markets but because they result in a net interchange of 0 MW for each intervening control area, there would not be any Energy delivered in real time. The ISO has had to confront such problems and has devised a number of solutions, including a requirement to identify a physical source for any submitted wheeling schedule (through tagging).

Option 3, like Option 2, permits a transaction with Energy originating in one system and serving Load in another, to pay only one access charge, and that charge would be assessed in the sink control area. The aggregate transactions for the year would be taken into account in setting the revenue requirements to be recovered through access charges for each control area. One difficulty with this option is that it will require close and explicit coordination among transmission providers in the region. While this difficulty can be eliminated in part by establishing larger regional transmission providers (e.g., RTOs), or by addressing the issue in seams agreements, during the transition period, there necessarily must be close coordination among RTOs and other transmission providers.

Despite the complexity involved, the ISO does not believe this creates an insurmountable hurdle. In fact, the ISO, working with its regional partners, RTO West and WestConnect, began to explore such an approach in 2001. Under the guidance of the Seams Steering Group–Western Interconnection (SSG-WI), the ISO, RTO West and WestConnect, established a "price reciprocity working group" whose mission was to identify and recommend options for eliminating transaction-based barriers to trade, such as pancaked transmission charges.

Option 3 is one of the options that the working group is actively considering. Under one proposal being considered by the working group, the participating RTOs (the ISO, RTO West and WestConnect) would waive access charges for export and wheel- through transactions. A second option provides that the RTOs would waive access and perhaps other charges that apply to exports and wheel through transactions and then recover any lost revenues through inter-RTO annual transfer payments. Under this approach, the RTOs (and their participating transmission owners) would continue to receive access charge revenues, but individual transaction charges would be eliminated, thus

reducing an important impediment to inter-regional transfers.[1] A final option under consideration by the working group is to establish a West-wide Wheeling Access Charge that would establish a wheeling charge applicable to use of certain Western high-voltage transmission facilities. The ISO believes that these options continue to present viable approaches for facilitating creation of a seamless West-wide market, and the ISO is committed to further discussions with its regional partners on these matters.

Option 4 appears to be a somewhat arbitrary compromise between Options 1 and 2 and, as such, seems to lack a theoretical or empirical foundation upon which to calculate the "lower" access charge for exports and wheel-throughs compared to the charge assessed within control area transactions. It appears that such an option may in part be based on the historical foundation for "non-firm" transmission service, wherein transmission providers offered discounted transmission service in order to maximize transmission usage and offset the cost of firm transmission service. However, because this service was non-firm in nature, service was curtailed whenever firm transmission service customers requested the use of available capacity. Thus, the notion of employing a non-firm transmission service to serve export or wheel-through transactions defeats the purpose of facilitating firm inter-regional

[1] However, the period payment does not resolve the concern about phantom wheel-throughs discussed under Option 2, because such schedules would still not face any transaction-based charges.

transmission service. However, as noted below, such an approach may work when considering options for addressing existing transmission contracts. Finally, if the purpose is to facilitate inter-regional transfers (as executed through export and wheel-through transactions) by offering a discounted service, the ISO believes Option 3 (as well as the other options under consideration in the West) offers a more transparent and viable approach.

The ISO notes that there is an important link between the two issues identified in Sections a.) and b.) above and a RTO's transmission planning and upgrade procedures. Under Option 2 in Section b.), the loads within a PTO area whose transmission system is used extensively for wheel-throughs might encounter substantial congestion from the wheeling transactions. Under an approach where export and wheel-through transactions would not pay access charges, but would be assessed congestion charges, the native Load may be opposed to any upgrade in its transmission system because such an upgrade would increase the access charges paid by native Load. The increase in access charges would occur in two ways: (1) through increased embedded costs; and (2) reduction in congestion revenues. The ISO believes it is important for an RTO to be able to sponsor transmission upgrades in order to relieve congestion without adversely impacting native Load, especially since such Load may receive proportionately only a small share of the benefits of such an upgrade. In the ISO's opinion, an optimal approach would be to allocate the costs of upgrades on a region-wide basis when such upgrades support region-wide trading. Developing an effective transmission upgrade program that allocates costs in this manner must go hand in hand with a regional access charge design that attempts to reduce or minimize charges to exports and wheeling transactions. Finally, if wheel-throughs are exempted from access charges, it will be even more important to grant native Load an adequate share of transmission rights, so that those entities who pay the access charge to recover the embedded costs of existing transmission facilities will receive protection from congestion caused by parties exempt from access charges.

c.) Should An Access Charge Be Based On Peak Load or Total Usage

The Commission sets out three options: (1) Option 1 which would use monthly peak load for billing the access charge; (2) Option 2 which would use annual peak Load as the basis for billing the access charge; and (3) Option 3 which would bill the access charge for each MWh used. Option 3 is the ISO's current method for assessing access charges.

The ISO notes that historical transmission system planning typically focused on peak system load conditions. Thus, transmission rates were established around those peak load requirements, and transmission access charges were developed based on either an average of the 12 monthly peaks or the annual peak load of the transmission provider. In 1998, the ISO established a load-based access charge that would be assessed based on the MWh scheduled through the ISO. This approach represented a departure from the typical historical practice that entitled an entity to schedule an amount of energy up to its transmission capacity (MW) entitlement. The ISO proposed a different approach that was consistent with the manner in which the ISO makes transmission capacity available to market participants. Thus, rather than offer transmission service through a transmission capacity reservation approach, the ISO makes transmission service available to all users of system based on submitted day-ahead (and hour-ahead) energy schedules, subject to congestion management adjustment and charges. Therefore, the ISO believes that it is reasonable to recover the embedded costs of the transmission system on a similar basis.

At the same time, the ISO recognizes that Options 1 and 2 are appealing because they (1) are consistent with the principle of cost causation in recognizing the impact of peak load conditions on transmission upgrade decisions, and (2) provide incentives for customers to increase their load factors (by reducing peak loads) where feasible. Option 1 may be a better approach for transmission systems with different winter and summer Load components because it takes into consideration different load patterns throughout the year. Option 2 appropriately rewards high load factor customers, i.e. those with constant Loads.

2. Transition Of Customers Under Existing Wholesale Contracts and Bundled Retail Customer Loads To Transmission Service Under a Revised Pro Forma Tariff

The Commission's Option 1 provides that all service would occur under an open access transmission tariff ("OATT") at the time the standard market design is implemented. Option 2 would convert bundled retail service customers upon implementation of the standard market design and provide incentives for customers under existing contracts to convert as well. Option 3 would permit regional variations.

The ISO agrees with the Commission that bundled retail service customers should be served under the OATT, as proposed under Options 1 and 2. Indeed, the ISO's current congestion management procedures as well as the congestion management procedures proposed in the ISO's MDO2 Filing reflect this approach. The far more difficult problem is how to deal with existing contracts.

Since its inception, the ISO has, as required by the Commission, continued to honor all Existing Transmission Contracts ("ETCs"). This obligation has created many challenges for the ISO and has frequently resulted in paper or "phantom" congestion. As explained repeatedly by the ISO, under the ISO's existing congestion management system, the ISO must first subtract all ETC capacity, whether actually scheduled or not, from the transmission capacity that is made available to market participants. Consequently market participants may be curtailed and/or charged (in the day-ahead and hour-ahead) for congestion that in reality does not exist. On occasions, this capacity has gone unused, yet other market participants have had their preferred schedules curtailed and have been charged for what turns out to be phantom (i.e., not real) congestion. This clearly distorts the forward congestion management market and impedes the efficient allocation of transmission capacity. As explained more fully below, this sub-optimal result is likely to be exacerbated under a nodal congestion management- pricing model – the model currently favored by the Commission in its Standard Market Design and the model used by the ISO in its MDO2 Filing.

Ideally, the ISO would like to see all market participants take service under a common transmission tariff. Indeed, such an outcome is imperative if the ISO's congestion management protocols are to produce meaningful, effective results. In particular, the strength of the locational marginal pricing ("LMP") congestion management approach proposed in the MD02 Filing depends on having consistent allocation and pricing rules in the forward and real time markets. Unfortunately, the requirement to serve two completely different classes of grid users – one class served under the OATT and the other served under ETCs – according to different transmission allocation and pricing rules and on different scheduling timelines, undermines the LMP design. The adverse impacts are in both the "long forward" time frame (i.e., release of FTRs)[2] and in the day-to-day operation of the ISO's markets.[3]

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[2] In determining how much transmission capacity is available for release to the market as FTRs, the ISO must first determine how much transmission capacity it must reserve for ETCs. Under the current FTR design, this problem is relatively simple, because FTRs are defined for individual transmission paths based on the available capacity on each path independently. Under LMP it will be necessary to (1) translate path-specific

The ISO recognizes, however, that abrupt termination of ETCs is also problematic and, therefore, a reasonable transition plan needs to be developed. Thus, as reflected in the ISO's MD02 proposal, the ISO prefers Option 2. The Commission should develop a reasonable transition plan that includes strong incentives to convert ETCs to a standard transmission tariff. The difficult task will be providing parties with ETCs adequate incentives to convert. Consistent with Option 3, the ISO believes that any such transition plan should accommodate an ISO's or RTO's unique circumstances.

Any transition plan for ETCs must address two aspects of ETC rights separately and sequentially: (1) the first-priority allocation of specific transmission capacity to ETC rights holders; and (2) the ability to reserve this capacity beyond the scheduling time line that applies to non-ETC users of the system. The ISO believes that the more urgent element, particularly from the viewpoint of inter-control area coordination of congestion management, is to require all parties, both those with ETC transmission and those using transmission service under the OATT, to schedule their transmission service on the same scheduling time line. Specifically, as with the ISO's OATT transmission service, any ETC capacity that is not scheduled in the day-ahead market should become available to accommodate the day-ahead schedules of

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ETCs into a pattern of injection and take-out points, and (2) assess the simultaneous impact of all ETCs to determine how much capacity is available for FTRs. This is a complex exercise because many ETC rights expand and contract with the operating transfer capacity (OTC) of the pathway, yet the ISO would have to translate them into a single MW value for FTR purposes. Moreover, the ISO is faced with an underlying tension that may have substantial consequences, i.e., to estimate ETCs too generously, release only a small amount of FTRs to the market and suffer extensive phantom congestion, or, in the alternative, to estimate ETCs too conservatively, release a larger amount of FTRs and then find the firmness of FTRs degraded by ETC rights holders using their ETC rights after the FTRs have been scheduled and congestion revenues frequently insufficient to compensate all FTR holders. Additional complexities created by ETCs are discussed later in this section.

[3] To illustrate, suppose that a load-serving entity ("LSE") tries to minimize its exposure to day-ahead congestion charges by bidding 500 MW less load in the day ahead market than it expects to serve in real time. The premise of LMP is that this LSE would be exposed to real-time congestion charges for the 500 MW of load. If, however, there is significant phantom congestion due to the ISO reserving ETC capacity that ends up not being used in real time, the expected real-time congestion charges do not materialize. Thus, the reservation of unscheduled ETC capacity beyond the day ahead market undermines the consistency between forward and real time markets upon which the incentive structure of LMP depends.

other transmission system users. Accordingly, the ISO submits that it is necessary that the Commission require ETCs to be reformed to conform to the standard

scheduling timelines applicable to all transmission users under the SMD tariff.[4] Concurrent with the imposition of such a requirement, the ISO recommends that the Commission ensure that whatever scheduling timelines are developed in the SMD rulemaking process be compatible with regional practices and accommodate, to the greatest extent possible, the need for market participants to make appropriate schedule adjustments as close to real-time delivery as possible. Finally, with respect to the contractual provisions of ETCs, the ISO recommends that the Commission prohibit TOs from renewing any ETCs as such contracts expire under their own termination provisions. This would be consistent with the Commission's actions in the natural gas industry with respect to individually certificated, Part 157 transportation services. Specifically, the Commission ruled that conversion to open access, Part 284 transportation service was appropriate for shippers whose contracts for individually certificated, Part 157 service expire/terminate.

The second problem associated with ETCs is the allocation of specific transmission capacity. This problem could get even worse under a detailed network/LMP-based congestion management model. In its MD02 Filing, the ISO noted the significant problem associated with the allocation of capacity to ETCs under a LMP congestion management approach. Specifically, the LMP approach necessitates, at a minimum, the development, allocation and provision of point-to-point (source-to-sink) FTRs. The FTRs in use in the existing ISOs that

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[4] This requirement by itself would provide a strong incentive for ETC rights holders to convert to FTRs and operate in full compliance with the OATT. Two additional incentives are that
(1) FTRs not needed for scheduling still earn congestion revenues and may be traded in secondary markets, and
(2) FTRs represent fixed MW rights, whereas ETC quantities typically expand and contract with OTC.

employ an LMP-based congestion management system are obligations. While algorithms for assessing simultaneous feasibility of such obligation rights are well tested and successfully used by these other ISOs, most ETCs do not fit this model. Instead, most ETCs are based on a defined contract path and are analogous to "options" rather than obligations.[5] Thus, in order for a transmission provider to both honor ETCs and offer FTRs under an LMP-based congestion management system, the transmission provider will have to ensure that both the ETCs (Options) and FTRs (Obligations) are simultaneously feasible. Because these are two different products, the task could prove to be quite difficult. In fact, to the ISO's knowledge, no entity has successfully developed a methodology or program to ensure that ETCs (Options) and FTRs (Obligations) are simultaneously feasible. In order to satisfy this objective, the ISO believes it will first have to subtract ETC capacity from the capacity it will make available for FTRs. This sequential approach will once again lead to the sub-optimal outcome outlined above whereby the ISO must reserve transmission capacity for ETC use recognizing that some of this capacity likely will go unused. Moreover, allocating transmission capacity to ETCs based on their *full* contractual capacity under a LMP-based model (i.e, using a detailed/accurate representation of the transmission system) may result in significant portions of the transmission system (and perhaps entire elements) being reserved for ETCs. The outcome may be that very few FTRs will be made available to other market participants.

In summary, the ISO believes that resolution of ETCs likely will be one of the most difficult issues for the Commission to resolve. It is also one of the most urgent because the requirement to maintain two separate and unequal sets of rules and procedures for two

[5] As the Commission has previously detailed, an obligation FTR creates an "obligation" to schedule in a particular direction because it carries a potential liability for congestion costs in the opposite direction if such schedule is not submitted. On the other hand, an option FTR provides an opportunity to schedule on a particular path in a particular direction with no potential exposure to congestion costs for not scheduling.

different classes of transmission users threatens to impede the creation of integrated regional markets. As a transitional approach, the simplest and most effective steps the Commission could take would be to (1) require ETCs to comply with the OATT scheduling time line, so that ETC capacity not scheduled in the day ahead market would become available to other customers in that market, and (2) preclude jurisdictional TOs from renewing ETCs once they expire.

3. Allocation of Transmission Rights

a. Should historical customers get the initial Transmission Rights?

The Commission identified two options for the allocation of Transmission Rights to existing customers. Option 1 would be to convert existing customers' usage to the initial Transmission Rights. Option 2 would be to give all customers that pay access charges the same rights to Transmission Rights.

The ISO believes the use of the transmission system by the existing customer must be recognized in any transition to a new standardized market design. By “existing customer” the ISO means native Load, which should be entitled to transmission rights, and should be able to retain possession of those rights regardless of which load-serving entity or wholesale transmission customer schedules power delivery or performs the intermediate transactions on the native Load’s behalf. In addition, to facilitate retail competition, such rights would move with the Load to whomever the load selects as its load-serving entity.

To the extent that exports and wheeling transactions pay the access charge, this principle would argue against Option 2. At the same time, the initial allocation of rights should also extend to new Loads connecting within the TO service area and to the Load growth of existing customers. Accordingly, the ISO cautions against a strict interpretation of Option 1 to mean only existing loads at their current historical consumption levels.

On the other hand, the ISO also cautions against allocating all initial Transmission Rights (or their auction proceeds) to the existing customers in excess of their actual needs. The ISO believes that rights should be allocated to existing customers as needed to meet historical demand, with timely adjustments (e.g., through allocations of monthly rights) as needed to serve Load growth and new loads that connect to the system. Any remaining transmission rights that can be made available should be auctioned, and the auction proceeds should be used to reduce the transmission access charge for all transmission users.

b. If existing customers are given the initial conversion rights, how should Transmission Rights be allocated?

The Commission identifies four options for allocating Transmission Rights to existing customers. Option 1 would assign rights based on existing contract rights and historical usage. Option 2 would auction transmission rights and assign the auction revenues based on existing contract rights (both real and implicit). Option 3 entails partial allocation and auction. Option 4 would permit regional variation.

As stated earlier, the ISO emphasizes that the use of the transmission system by the existing customer must be recognized in any transition to a standardized market design. To that end, Option 1 comes closest to preserving the rights that customers have prior to the new market design. Theoretically, Options 1 and 2 should produce the same end result if there is a liquid secondary market for trading transmission rights. Option 2 makes the FTR auction process more liquid and generates more revenues. Option 2 would allow customers to value transmission based on need. In California, however, Option 1 is more appealing due to the diversity of loads and load-serving entities that use the ISO control area. In particular, many ISO system users generally seem to prefer a system in which their needed transmission rights are allocated prior to any auction, thereby eliminating the need for auction participation and the risk of being out-bid for some amount of needed transmission rights. Option 1 does not discourage the participation of new suppliers because it would permit Load to retain Transmission Rights if it chooses new suppliers.

Option 3 appears to be somewhat arbitrary, because the Commission does not provide any basis or guidance as to how to determine what percentage of the transmission rights should be allocated and what percentage auctioned.

The ISO prefers a mix of the options. As stated above, the ISO believes that existing customers should be allocated transmission rights, but only to the extent such rights are required to serve historical demand and demand growth. Any remaining transmission rights should be auctioned and the proceeds used to reduce the transmission access charge for all transmission users. The ISO also supports Option 4, which provides for regional variation.

4. Long-Term Generation Adequacy

The final issue raised in the Options Paper is the type of mechanism that should be in place to ensure long-term generation adequacy, as well as who should administer the program. Under Option 1, LSEs would be responsible for acquiring sufficient supplies to meet their needs and would rely on energy prices and information regarding the projected supply/demand situation compiled by the transmission provider. Option 2 would establish a regional supply obligation and each LSE would be obligated to obtain sufficient supply to meet its proportionate share of such regional supply obligation. Option 3 would establish a regional capacity obligation, and the transmission provider would determine the capacity obligation for each LSE. Option 4 would impose a supply obligation on load serving entities only if projected reserves fall below a trigger level. Finally, Option 5 would set capacity obligations for operating reserves only as forward reserves contracts.

The concept of supply adequacy, and, concurrently, the ability to share reserves between parties, has a long history in the electric utility industry. The need to ensure long-term generation adequacy historically was driven by each vertically integrated utility's obligation to serve its native load (load located within its franchised service territory or area). Such an obligation (as overseen by the utility's local regulatory authority) created a need for utilities to build or contract for sufficient capacity to serve that load. Along the way, utilities recognized that they could benefit and achieve certain efficiencies from pooling their resources, i.e., sharing the installed reserves among utilities. Upon the introduction of competitive markets to the industry, the obligation to serve load became less clear. In California, emphasis and reliance on spot markets increased, and fewer entities took advantage of long-term contractual arrangements to satisfy their known obligations. With the possibility of load moving from one supplier to another (as in a retail access environment), there was an inherent risk to an LSE in procuring substantial amounts of power to serve load that may choose to move to another provider, thereby resulting in stranded costs.

In California, the end result was an over-reliance on the spot (day-ahead and real time) energy market as a resource to serve load. The use of the spot market as a significant resource for serving load resulted in three outcomes: (1) consumers were increasingly subjected to highly-volatile spot market prices; (2) load-serving entities and their customers were more prone to the exercise of market power by suppliers because the suppliers knew such entities had to buy power through the spot market (i.e., at the last moment); and (3) the bulk power supply system became less reliable because the ISO was unable to identify, in advance, the resources necessary to serve the next day's forecast load. Thus, any measures adopted by the Commission to ensure long-term generation adequacy must support reliable system operation and should not rely solely, or substantially, on volatile spot market prices as an incentive for investment, especially in conditions where those prices are subject to market power manipulation.

To this end, the ISO notes that the issue of supply adequacy is probably the one issue discussed in the Options Paper where federal-state cooperation is most imperative. While issues related to the reliable operation of the transmission system and the proper functioning of wholesale energy markets are clearly within the Commission's purview (i.e., the Commission can establish a generic capacity/supply obligation on LSE's to ensure system reliability and workable wholesale energy markets), matters regarding an individual LSE's specific procurement activities and the resource mix used by the LSE to satisfy such LSE's obligations are appropriately addressed by local regulatory authorities. The ISO believes that such a division of responsibilities is appropriate and can work – as is evidenced in the established eastern ISOs and, prior to that, in the East's tight power pools. Because the objective of any measures adopted by the Commission to ensure long-term supply adequacy should be to support reliable transmission system operation and properly functioning wholesale markets, such measures should apply to all users of the system – no matter what the jurisdictional boundaries.

Under this division of responsibility, the issue of how to address long-term supply adequacy can be divided into two components. The first component is providing the correct incentives for LSEs (and their state and local regulators) to ensure adequate supplies to serve the loads they are responsible for and to cover their proportionate share of reserves. This component is dependent in large part on the policies implemented by state and local regulators. Whatever incentives are created by the ISO or RTO, the LSEs and their regulators will incorporate these incentives as just one element of an overall supply procurement framework which includes state public policy regarding state-jurisdictional entities' procurement activities, the state's resource and fuel-type mix, the state's environmental policy, and other matters appropriately decided by state public policymakers.

The second component of this issue focuses on the minimum supply requirements for reliable transmission system operation and the actions a transmission system operator should or can take when one or more LSE is short of supply. Based on the ISO's experience, this second component can be the most difficult one for a transmission system operator to manage because the actions that must be taken to manage shortfalls are usually taken in real time. The ISO therefore is seeking to develop an approach that provides unambiguous direction to the grid operator, well in advance of real time, about what actions it must take in real time (i.e., when, whom, and how much load to curtail, or how much to spend on last-minute energy purchases that may be needed to avoid curtailing), while at the same time holding supply-short LSEs fully accountable for the consequences of their shortfall.

Thus, the ISO believes that the Commission should focus on these core requirements, so that transmission providers will be able to (1) have effective procedures for ensuring reliable operation of the transmission system when LSEs fail to procure sufficient supply resources to meet their load and reserve needs, and (2) hold supply-deficient LSEs responsible for their under-procurement in order to prevent negative impacts on supply-sufficient LSEs. Once these generic requirements are satisfied, the transmission provider should be able to leave specific procurement decisions to the LSEs and their regulators.

That being said, the ISO notes that holding supply-deficient LSEs responsible for their deficiency is no simple matter, particularly when there is retail competition and multiple LSEs serve load within any given distribution company's service territory. For example, it would be desirable for the ISO to selectively curtail the load of a deficient LSE when supply is short in real time but, at present, utilities lack the technical capability to do this. However, as further explained in the ISO's MD02 Filing, the ISO is committed to working through this and other technical barriers in order to develop an effective capacity requirement, with clear and unambiguous rules, that will ensure reliable system operation and a properly functioning market.

With regard to the Commission's proposed options, the ISO's experience provides empirical evidence that Option 1 should not be adopted. Theoretically, Option 1 can only work so long as consumers are willing to live with short-term price volatility and long-term price cycles due to capacity boom and bust periods. Realistically, such a model is likely to be unsustainable because it will invite political intervention when capacity is scarce, which in turn may exacerbate the shortage by creating an uncertain investment climate. Option 1 also suffers from the potential to place an unreasonable real-time operating burden on the transmission operator, because it encourages LSEs to gamble on spot prices. Specifically, Option 1 does not create any explicit enforcement mechanism to ensure that LSEs procure adequate supply/capacity in the forward market. In the event the LSE loses its gamble, the grid operator must be able to target a blackout precisely at the short LSE, which is not feasible at present when there are multiple LSEs operating within a single distribution service territory. For these reasons the ISO does not favor Option 1.

Options 2 and 3 are similar in many respects with their major differences centering on the timing of the obligation and the enforcement mechanisms. Option 2 generally has a longer time horizon (one to five years), whereas Option 3 addresses supply adequacy on a shorter time frame (monthly, seasonally or annually). Option 2 could be made more effective if, in addition to putting a supply adequacy obligation on load serving entities, it pre-conditioned supplier market-based rate authority on offering long-term supply contracts (at just and reasonable rates) up to a minimum percentage of its portfolio, or until the collective action of all suppliers reached the supply adequacy target.

Both Options 1 and 2 have a weak enforcement mechanism that focus on the grid operator curtailing load, if necessary, for those LSEs that are short of supply. As noted above, although this may be attractive in theory, it may not be operationally feasible in the near term. To the extent it is not feasible, the enforcement mechanism will fail. Option 3 uses a financial penalty as the enforcement mechanism, and the transmission operator provides a market in which LSEs can purchase capacity to meet their obligations. The ISO is concerned that this approach may encourage parties to play to the requirement, i.e., to trade-off last-minute market purchases or penalties against the cost of forward contracting for supply rather than to take a fully prudent long-term planning approach. Again, the success of either approach will depend on how state and local regulators choose to address the problem.

Option 4 limits the imposition of supply or capacity requirements on the load serving entities (i.e., requirements relevant to Options 2 and 3) only to the hours when the ISO is short on reserves. This option could lead to erratic and volatile markets for supply adequacy and, relative to Options 2 and 3, offers less effective market incentives for new generation investment. Finally, Option 5 rests on the sound economic basis of call options, but it also makes the transmission provider an active market participant, which may conflict with the underlying mandates of an RTO or ISO.

In summary, the ISO believes that Option 2 is the preferred option, but it requires a solution to the problems of holding a supply-deficient LSE fully accountable when its deficiency materializes in real time, and preventing that deficiency from having adverse cost or reliability impacts on supply-sufficient LSEs and the system as a whole.

5. Conclusion

As detailed above, the ISO strongly supports the majority of specific elements set forth in the Options Paper and, in many cases, has already incorporated such design elements in its MD02 Filing. The ISO urges the Commission to give consideration to the several specific comments set forth above in finalizing options for resolving rate and transmission issues as well as finalizing a standard market design.

Respectfully submitted,

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Dated: May 30, 2002