O. ISSUES ON REHEARING

O.1. With respect to ISO charges:

a. Whether the Congestion Management and the Usage Charge components of the ISO Tariff's transmission pricing provisions are unjust and unreasonable (e.g. result in improper cost shifts and improper ("and" pricing) not in conformance with the Commission's Transmission Pricing Policy? [Issue No. 637, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, EC96-19-009, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, ER96-1663-010 OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponents - City and County of San Francisco, Cities / M-S-R, and Palo Alto]

(1) "And" Pricing.

Proponents allege that "[t]he Congestion Management and Usage Charge pricing provisions in Sections 7.1 and 7.3 of the ISO Tariff violate the Commission's ban against 'and' pricing." Joint Initial Brief on Issue O.1.a, at 6. In support of this proposition, Proponents argue that payment by a transmission customer of an Access Charge *and* a Usage Charge is equivalent to payment of an embedded cost plus an opportunity cost, which Proponents urge is proscribed by the Commission's "and" pricing policy under the Commission's Transmission Pricing Policy Statement,[204] as well as by the *Penelec* case.[205] *Id.* at 6-13. Proponents concede that the ISO's Congestion Management Usage Charge

[204] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Policy Statement*, FERC Stats. and Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,005 (1994), *Order on Reconsideration*, 71 FERC ¶ 61,195 (1995) ("Transmission Pricing Policy Statement").

does not result in an over-recovery of transmission revenues, but they argue that this is irrelevant. *Id.* at 7-8. Instead, Proponents contend that the essence of prohibited "and" pricing is a subsidy by one customer group of another. *Id.* at 10-13. Proponents claim that such a subsidy takes place under the ISO's Congestion pricing approach because some customers pay more than others for transmission service. That is, transmission customers on the import side of a congested transmission interface pay a Congestion Usage Charge that other, "uncongested" customers do not pay; residual Usage Charge revenues not disbursed to Generators for relieving Congestion are then used to reduce the Revenue Requirement of the owner of the congested interface, thus lowering the Access Charge paid by all its customers, including both "congested" and "uncongested" customers. *Id.* at 7-8. Proponents argue that the only way to remedy this situation is to flow back all residual Usage Charges to the congested customers that incurred them. *Id.* at 7.

In the next section the ISO will show that the ISO's differential Congestion pricing approach alleviates rather than creates cost shifts and subsidies, and that it does not violate the Commission's "and" pricing rules.

(i) Transmission Pricing Policy Statement

Proponents appear to have misunderstood the Commission's Transmission Pricing Policy Statement. Proponents' initial brief casts the Pricing Policy Statement as a document laying down generic rules prohibiting

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[205] *Pennsylvania Electric Utility Co.*, 58 FERC ¶ 61,278, *reh'g denied and pricing policy clarified*, 60 FERC ¶ 61,034, *reh'g denied*, 60 FERC ¶ 61,244 (1992), *aff'd sub nom. Pennsylvania Electric Co. v. FERC*, 11 F.3d 207 (D.C. Cir. 1993).

opportunity cost or marginal cost transmission pricing in addition to a "postage-stamp" embedded cost charge. *Id.* at 8-9. Thus, Proponents argue that the Pricing Policy Statement precludes use of a Usage Charge in addition to an Access Charge. However, contrary to Proponents' contentions, the intent of the Pricing Policy Statement was to relax the inflexible requirements that had previously circumscribed transmission pricing methodologies, and to invite new and creative approaches appropriate to the restructured electricity markets. Indeed, while holding to its prohibition against "and" pricing, the Commission has steadfastly refused to interpret the Pricing Policy Statement as generically precluding pricing mechanisms that include both embedded cost and marginal cost or opportunity cost pricing:

> [I]f the pricing flexibility envisioned in the Policy Statement is to be achieved, a case-by-case approach to transmission pricing, not a generic approach, is appropriate.
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> * * * * *
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> We stand by our policy of allowing utilities to include opportunity cost charges in their transmission rates. . . . [W]e will have ample opportunity to address any concerns that opportunity cost pricing may be unfair and anticompetitive or otherwise inconsistent with the comparability standard in the course of our evaluation of a particular transmission pricing proposal. . . . [W]e do not agree that marginal cost pricing requires that all customers be charged the same price.
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> * * * * *
>
> [W]e also believe that providing more efficient price signals through the use of marginal cost pricing can influence efficient siting decisions. . . . [W]e believe that marginal cost pricing will promote efficient decision-making by both transmission owners and users.

> As a result, we encourage experimentation regarding marginal cost pricing proposals . . . .[206]

Clearly, rather than violating any policy or rule laid down by the Pricing Policy Statement, as Proponents argue, the Commission in this case has made good on its promise to analyze opportunity cost and marginal pricing proposals on a case-by-case basis. In this case it has found that the ISO's Congestion pricing proposal serves the causes of efficiency and comparability, and fulfills the Pricing Policy Statement's tests:

> As we stated in our Transmission Pricing Policy Statement, we fully intend to be flexible and to consider innovative, conforming pricing proposals that accommodate the changing needs of the marketplace as are present in this proceeding. Therefore, we conclude that the ISO's transmission pricing proposal does not raise the same concerns addressed in our earlier orders.
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> * * * * *
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> In the Transmission Pricing Policy Statement we enunciated five principles we would use in evaluating transmission pricing proposals. The ISO's transmission pricing proposal satisfies these five principles.
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> *Principle No. 1 – Meets the Revenue Requirement.*
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> A "conforming" pricing proposal must generate revenues that do not exceed the transmission owner's revenue requirement. The ISO's proposal satisfies this principle. The combined revenues received by any transmission owner from access charges and congestion charges would not exceed its embedded cost revenue requirement. Any congestion revenues received by a transmission owner would be used to reduce its access fee.
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> *Principle No. 2 – Reflects Comparability.*
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> Any new transmission pricing proposal must meet the Commission's comparability standard. All users of the ISO Grid

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[206] Transmission Pricing Policy Statement, *Order on Reconsideration*, 71 FERC at 61,689-91 (footnotes omitted).

> would pay an embedded-cost-based access fee and, to the extent they utilized a congested transmission path, congestion charges. Therefore, the ISO's proposal satisfies our comparability principle.
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> *Principle No. 3 – Promotes Economic Efficiency.*
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> Transmission pricing should promote: 1) efficient expansion of transmission capacity; 2) efficient location of new generation and load; 3) efficient use of existing transmission facilities, including constrained capacity; and 4) efficient dispatch of generating resources. For reasons explained above, the ISO's transmission pricing proposal would promote an efficient use of the existing generation and transmission facilities and promotes efficient expansion.
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> *Principle No. 4 – Promotes Fairness.*
>
> The ISO's proposal is fair. The ISO's proposed pricing framework does not distinguish between different classes of transmission customers. Secondly, the ISO's proposed transmission pricing proposal mitigates the economic harm imposed on customers by preventing any cost-shifting during the transition period.
>
> *Principle No. 5 – Pricing Should Be Practical.*
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> To satisfy this principle we require that a user should be able to calculate how much it will be charged for transmission service. ISO customers will be able to ascertain the cost of transmission service. ISO customers will be assessed a clearly stated access charge. In addition, ISO customers will have access to ISO-posted information and will have the opportunity to adjust their usage based on forecasted congestion. While the Commission recognizes that congestion pricing is complex, we believe that the gains in efficiency outweigh the burden of such complexity.

Pacific Gas and Electric Company, et al., 80 FERC ¶ 61,128, 61,430 (1997) (footnote omitted). While the Transmission Pricing Policy Statement itself may have expressed doubts about the likelihood of an "embedded cost plus marginal cost" proposal meeting the requirements of the Pricing Policy Statement, as Proponents contend (Joint Initial Brief on Issue O.1.a, at 3), these doubts have been dispelled by the Commission's careful analysis of an actual proposal, as contemplated by the Pricing Policy Statement itself. Thus, the Commission has not been irresponsible in accepting the ISO's pricing approach, as Proponents have alleged. *Cf. id.* at 13 n.23. On the contrary, the Commission's acceptance is consistent with its approach in many recent cases:

> We disagree that we have departed from our policy against "and" pricing. The form of "and" pricing that the Commission has prohibited is described in the Transmission Pricing Policy Statement. There we addressed "and" pricing at the corporate level, *i.e.*, proposals by individual transmission providers to assess certain customers both an embedded cost rate and an incremental cost rate, while assessing only an embedded cost rate in their own uses of the transmission system. While the pricing proposals we will entertain for RTOs may combine elements of embedded cost rates and incremental cost rates, they do not constitute corporate "and" pricing. Indeed, we have already approved these rate forms for most existing ISOs, noting for example, that it is acceptable to charge both a non-pancaked access fee based on embedded costs and an incremental charge reflecting opportunity costs or expansion costs. Significantly, unlike the corporate "and" pricing prohibited under our Transmission Pricing Policy Statement, the objective of this pricing proposal is not to make the cost faced by one group of transmission users (*i.e.*, the wholesale customer) higher than another's (*i.e.*, native load). Rather, this type of pricing is intended to (1) reduce the cost of transmission over multiple utility systems in both constrained and unconstrained situations and (2) rely on congestion charges to provide a uniform price signal to all users in constrained situations.[207]

(ii) <u>The *Penelec* Case</u>

Proponents' analysis of the *Penelec* case is similarly flawed. For example, Proponents argue that the "thrust" of *Penelec*'s "and" pricing proscription "is to prevent unfair subsidization of customer classes rather than to prevent utility over-recovery of transmission revenue requirements." Joint Initial

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[207] Order No. 2000-A, FERC Stats. and Regs., Regs. Preambles ¶ 31,092, at 31,388. *See also Mountain West Independent System Administrator*, 90 FERC ¶ 61,067, at 61,256 (2000); *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC at 62,259-60. These two cases are discussed further below.

Brief on Issue O.1.a, at 13. But this is simply incorrect. Preventing over-recovery was a major consideration underlying the holding in *Penelec*; in fact, it was a consideration which the Commission used to the exclusion of others in its summary of the holding: "We believe that if Penelec agrees to [use the Commission's prescribed pricing approach], its proposed Transmission Service Agreement will not produce excessive revenues." *Penelac*, 58 FERC at 61,871. Proponents have conceded that the ISO's proposal does not result in over-recovery of transmission revenues.

Also, while Proponents have recognized that encouraging economic efficiency was also a major underpinning of the *Penelec* holding (*see* Joint Initial Brief on Issue O.1.a, at 12), they fail to recognize the importance of the Commission's finding that the ISO's differential pricing approach to Congestion Management sends price signals that *encourage* efficiency:

> We agree that the congestion usage charge sends the proper price signals regarding the opportunity costs of using congested transmission paths. The usage charge will encourage efficient usage of the transmission system and facilitate the development of a competitive electricity market. By efficiently pricing the use of constrained transmission capacity, the ISO's proposed usage charge will also send the proper price signals for the location and dispatch of existing and new generating resources.

Pacific Gas and Electric Company, et al., 80 FERC at 61,429. This is a second major distinction between the instant case and *Penelec*, where, as Proponents point out, the Commission determined that the proposed "and" pricing mechanism was anticompetitive and inefficient. Joint Initial Brief on Issue O.1.a, at 12.

A third distinction between this case and *Penelec* that Proponents fail to note is the fact that in the present case the ISO proposes to apply the same pricing formula – through use of Sections 7.1 and 7.3 of the ISO Tariff – to all transmission customers. By contrast, the pricing discrimination in *Penelec* could scarcely have been more conspicuous: Penelec proposed to charge its own native load customers one rate and its third-party transmission customers another (higher) rate per kilowatt-month – regardless of congestion, losses, location, or any other variables. *Penelac*, 58 FERC at 61,870. This discriminatory purpose was a major factor in the Commission's decision in *Penelec*.

Fourth, it is worth noting that *Penelec* was decided in a very different context than the present case. In *Penelec*, an investor-owned utility company sought to subsidize the electric rates of its own native load customers by charging higher prices to third-party transmission customers. *Id.* at 61,873. Here, the entity setting the rate is a not-for-profit corporation run by management committees including representatives of all of its customer classes for the benefit of these customers. This entity has no native load customers, and no incentive to favor one group of customers over another. The ISO has adopted the Congestion pricing approach with only one objective: to maximize equity and economic efficiency of transmission pricing in the new electricity markets. Its pricing formula is applied even-handedly to all customers.

Indeed, the Commission has recognized that different circumstances and contexts call for different outcomes:

> [T]he circumstances here differ from those we considered in the Transmission Pricing Policy Statement and other earlier orders concerning "and" pricing. In Pennsylvania Electric Company (*Penelec*), the Commission stated that the basic ratemaking goals that would guide our assessment of transmission pricing proposals would be: 1) holding native load customers harmless; 2) charging third-party customers the lowest reasonable cost-based rate; and 3) preventing transmission providers from collecting monopoly rents. In *Penelec*, the Commission was concerned with resolving the conflicting goals of holding an individual utility's native load customers harmless and charging third-party customers the lowest reasonable rate. In this instance, there is no tension between native load and third-party customers – all customers are treated the same. All customers using the ISO Grid will be charged only a single stand-alone transmission utility access charge and, if applicable, a congestion usage charge. The pricing being proposed in the California Restructuring is intended to reduce the price of transmission over multiple utility systems in unconstrained situations and to rely on congestion charges to provide a uniform price signal to all users of a given transmission interface.

Pacific Gas and Electric Company, et al., 80 FERC at 61,429-30.

Finally, the Commission's holding in this case is consistent with its holdings in other cases involving ISOs using differential pricing for Congestion Management. Thus, in the *Mountain West Independent System Administrator* and *Pennsylvania-New Jersey-Maryland Interconnection* cases, cited above, the Commission approved Congestion Management pricing methodologies that involve charging congested customers higher transmission rates than uncongested customers, on grounds similar to those discussed here (i.e., economically efficient price signals, no over-recovery of transmission revenues).[208]

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[208] *See also Mountain West Independent System Administrator*, 90 FERC at 61,252 ("The Commission has also allowed ISOs in PJM and New York to charge transmission prices reflecting congestion costs that are derived from differences in locational energy prices established in energy auctions.").

Consequently, the Commission should reject Proponents' contention that the ISO's differential pricing proposal for Congestion Management violates the Commission's proscription against "and" pricing.

(2) Cost-Shifting and Subsidies.

Proponents assert that the ISO's differential pricing approach to Congestion Management causes impermissible cost shifts and subsidies between groups of transmission customers, in violation of Commission precedent and policies. Joint Initial Brief on Issue O.1.a, at 3, 13-14. Proponents' reasoning is as follows: congested customers pay a Usage Charge, which uncongested customers do not pay; part of this Usage Charge is then in effect flowed back to transmission customers, but because it is flowed back equally to all customers, uncongested customers receive a benefit from the Usage Charge payments made by congested customers. Proponents argue that this regime advantages uncongested customers at the expense of congested customers, and creates improper cost shifts and subsidies from congested to uncongested customers. *Id.* at 12-13.

(i) Economic Analysis

Proponents' arguments ignore the economic realities of the electricity market. Consumers who live in a region where it costs more to deliver a particular good or service are not discriminated against when such a good or service costs them more; rather, this cost differential is a result of market forces. As Professor Hogan (the expert whom Proponents cite in their initial brief) has shown, the market price of electricity likewise depends on the location where it is consumed.[209] One factor that will drive up the market price of Energy at a particular location is the existence of a constraint or bottleneck to its transmission to this location. In the presence of such a bottleneck, suppliers of electricity to customers behind the bottleneck will compete for its use by bidding up the transmission price of the constrained pathway for their own deliveries of Energy. These higher prices will then be passed along to the electricity customers. Under such conditions, customers behind such a bottleneck – congested customers – will naturally pay higher prices for electricity than customers outside the bottleneck area. To the extent that they do not, this has to be because of cost spreading (i.e., the uncongested customers paying part of the higher market price of electricity applicable to the congested customers) – which constitutes a cost shift or subsidy running from the uncongested customers to the congested customers.

It is exactly this kind of cost shift and subsidy that the ISO's Usage Charge is intended to prevent. The Usage Charge is calculated based upon how much it costs in the free market to relieve or counteract the transmission constraint by adjusting Generation on either side of the constrained interface.[210] Consequently, it is *not* the case that the Usage Charge creates cost shifts or subsidies among different groups of customers; on the contrary, it is the Usage Charge that *prevents* such cost shifts or subsidies from occurring.

209 *See generally* Scott M. Harvey and William W. Hogan, *Nodal and Zonal Congestion Management and the Exercise of Market Power* (Jan. 10, 2000). This report is the attachment to the Motion to Intervene and Comments of Sempra Energy, Docket No. ER00-703-000 (Jan. 10, 2000). *See also* Joint Initial Brief on Issue O.1.a, at 20 n.34 (citing this report).

210 *See* October 1997 Order, 81 FERC at 61,457-58; *Pacific Gas and Electric Company, et al.*, 80 FERC at 61,429.

Consequently, and contrary to the allegations of Proponents, the ISO's differential pricing approach to Congestion Management actually prevents cost shifts and subsidies in real economic terms. As such, its removal would create the inequities of which Proponents complain.

(ii) Economic Efficiency

The analysis presented above is sufficient to establish the need for the ISO's differential pricing approach. However, an additional reason to approve this pricing approach is the fact that only this approach provides incentives for rational economic decisions concerning siting for future Generation, Load, and expansion of transmission facilities. The Commission has recognized this fact:

> By efficiently pricing the use of constrained transmission capacity, the ISO's proposed usage charge will also send the proper price signals for the location and dispatch of existing and new generating resources. To the extent generation located on the high cost (import) side of a constraint is priced higher as a result of congestion usage charges, generation that would otherwise be more expensive but for the usage charges will be dispatched first. Therefore, new load will have an incentive to locate on the low cost (export) side of the constraint, and new generation will have an incentive to locate on the high cost (import) side of the constraint. Moreover, the ISO's proposed congestion usage charge is also likely to encourage efficient expansion of the transmission system. For example, to the extent that, over time, congestion usage charges are higher than the cost to expand constrained transmission capacity, transmission customers will have an incentive to expand the transmission system.

Pacific Gas and Electric Company, et al., 80 FERC at 61,429. Thus, use of the differential pricing approach to Congestion Management will result in relief from the high prices paid by congested customers of which Proponents complain – but it will do so in real economic terms, rather than cosmetically through the use of hidden subsidies and cost-shifting. The ISO sees it as its duty to promote such economic efficiencies for the benefit of all electricity customers.[211]

(iii) Comparability and Non-Discrimination

The ISO has already demonstrated above that the ISO's Usage Charge formula is applied uniformly and in a non-discriminatory manner to all users of the transmission system. The ISO has also shown that the ISO's differential pricing approach treats all customers comparably by preventing cost shifts and subsidies among groups of customers.

However, Proponents spend most of section IV.A.3. of their initial brief (dealing with comparability and discrimination issues) arguing that certain policies adopted by the CPUC diminish the effectiveness of price signals sent to Load by the ISO's pricing approach. Thus, Proponents point out that PG&E is currently subject to a retail rate freeze, and that CPUC policy requires public utilities to charge all retail customers uniform rates, whether they are located in congested or uncongested transmission areas. Joint Initial Brief on Issue O.1.a, at 16-18. Proponents claim that these policies prevent price signals sent by the ISO's Congestion pricing approach from reaching these customers, thus vitiating the efficiency arguments supporting the pricing approach as to these customers. Proponents also argue that the combination of the CPUC's policies and the ISO's pricing approach discriminates against municipal utilities, which are smaller than the California public utility companies. Proponents state that this is because

[211] The expert report cited in Proponents' initial brief agrees: "California consumers, at least in aggregate, would be best served by an efficient competitive market. . . . [T]he California ISO should simply seek to coordinate a competitive and efficient generation market . . . ."

such municipal utilities are unable to spread Usage Charges they may incur over as large a pool of customers as the public utilities, thus raising their average rates relative to those of the public utilities, and thus making it more difficult for them to compete for customers. *Id.* at 15-16.

Several responses can be made to Proponents' arguments. First, as Proponents themselves recognize (*id.* at 17), these arguments relate only to the Load side of the equation; the CPUC policies Proponents identify do not weaken price signals to Generators.

Second, obviously the CPUC's jurisdiction extends only to retail customers; wholesale transmission customers are thus unaffected by these CPUC policies. Consequently, the wholesale portion of the Load equation will respond to the price signals sent by a differential pricing Congestion Management approach.

Third, as Proponents point out (*id.* at 15-16), the municipal utilities about which Proponents are concerned have not yet joined the ISO, and are thus not yet subject to the ISO's differential pricing formula. These municipal utilities are functioning as they have for many years under Existing Contracts, which are being honored under the ISO Tariff. *See* ISO Tariff, Section 2.4.4.1.1. In addition, San Francisco, one of the proponents, is located in an Inactive Congestion Zone, meaning that any Usage Charges applicable to its electricity are spread among all customers in that Zone and the Active Zone on the other side of the applicable constrained transmission interfaces. Thus, the parties for

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Scott M. Harvey and William W. Hogan, *Nodal and Zonal Congestion Management and the Exercise of Market Power* (Jan. 10, 2000), at 5-6.

whom Proponents express concern will have a period of time before they become subject to any Usage Charges to review the capacity of the transmission facilities on which they are dependent, and to effect changes or expansions to preclude the need to pay Usage Charges when and if they do become subject to the ISO Tariff.

Finally, and most importantly, Proponents have themselves recognized that the vitiation of price signals and the downstream effects they fear are a result of CPUC policies and requirements. The ISO agrees that economic efficiency in the California electricity market would be enhanced if some of these policies and requirements were changed. However, the Commission has no authority to effect such changes. At the same time, while the Commission owes deference to the state regulatory authorities, this deference is limited by the Commission's duty under the FPA to set just and reasonable rates for the transactions under its jurisdiction. *See, e.g., FPC v. Southern California Edison Co.*, 376 U.S. 205, 215 (1964). No one has argued that the ISO's Congestion Management processes are outside the Commission's jurisdiction. Consequently, the Commission has a duty to promulgate nondiscriminatory and economically rational rules governing ISO transactions. As the ISO has shown above, the ISO's differential pricing system is such a rule, and its removal would have discriminatory and economically irrational effects. While the CPUC's policies may partially frustrate the achievement of some of the Commission's goals for the ISO's Congestion pricing approach, the ISO's Congestion approach does not frustrate any California regulatory policy. Thus, the Commission should preserve the concept of differential pricing for congested and uncongested transmission.

(iv) Fairness and Practicality

As shown above, the Commission has found that the ISO's pricing approach is fair: "The ISO's proposed pricing framework does not distinguish between different classes of transmission customers. Secondly, the ISO's proposed transmission pricing proposal mitigates the economic harm imposed on customers by preventing any cost-shifting during the transition period." *Pacific Gas and Electric Company, et al.*, 80 FERC at 61,430.

In addition, the Commission has recognized that the complexity of Usage Charge calculations under the ISO's differential pricing approach is an artifact of the actual complexity of the market variables involved, and cannot be blamed on deficiencies in the ISO's pricing approach:

> ISO customers will be assessed a clearly stated access charge. In addition, ISO customers will have access to ISO-posted information and will have the opportunity to adjust their usage based on forecasted congestion. While the Commission recognizes that congestion pricing is complex, we believe that the gains in efficiency outweigh the burden of such complexity.

Id.

(3) Conclusion.

Proponents have correctly noted that the Commission has directed the ISO to undertake a reevaluation of its overall Congestion Management approach, with input from stakeholders. Joint Initial Brief on Issue O.1.a, at 20. Proponents imply that the Commission can safely approve their objections to the ISO's current pricing approach pending the outcome of this reevaluation. Nothing could be further from the truth. The essence of all of Proponents' arguments against the ISO's pricing approach is that it is impermissible to charge congested customers a higher transmission rate than uncongested customers. However, this concept of differential pricing is fundamental to any Congestion Management methodology that proposes to send economically efficient price signals to Market Participants, including the locational (nodal) methodology endorsed by Proponents (*see id.* at 20-21). Thus, should the Commission accept Proponents' arguments, it would in effect be precluding the ISO from proposing any new Congestion Management methodology – zonal, locational, or other – that involves differential price signals being sent to congested and uncongested customers. For this reason, the ISO respectfully requests that the Commission reject Proponents' arguments and deny their requested relief pending the outcome of the ISO's reevaluation of its Congestion Management system.

b. <u>Is the allocation of unaccounted for energy ("UFE") to wholesale transmission customers who have not signed Utility Distribution Company Agreements, unjust, unreasonable or unduly discriminatory? [Issue No. 655, Docket Nos. EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, EC96-19-009, ER96-1663-001, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, and ER96-1663-010. Proponents - DWR and MWD]</u>

<u>Improvements to the Calculation of UFE</u>

As explained in regard to Issue L.5, above, UFE charges that ran substantially higher than expected from April through September 1998, and again in the fall of 1999, were largely caused by transmission-level, not distribution-level, meter data management errors. These errors were corrected, and the accounts of Scheduling Coordinators were adjusted to reflect the corrections. Furthermore, the calculation and allocation of UFE have been improved since the ISO Operations Date. One improvement has been the identification and recommendation of a methodology to better differentiate transmission-level UFE from distribution-level UFE, and to allocate it on the basis of cost causation. Therefore, only small amounts of distribution-level UFE costs are in today's ISO UFE charges. The concerns that gave rise to DWR's and MWD's objections to the manner in which the ISO Tariff defines and charges UFE costs have largely been ameliorated. The ISO's method of charging UFE costs is just, reasonable, and not unduly discriminatory.

(1) <u>The ISO's Tariff Requires It to Calculate UFE Charges Separately for Each UDC Service Area.</u>

The ISO Tariff provides that UFE on the ISO Controlled Grid is to be calculated separately for each UDC Service Area and for each Settlement Period. *See* ISO Tariff, Appendix A, definition of "Unaccounted for Energy." UFE is defined as the difference in Energy between the net Energy delivered into the UDC Service Area (adjusted for UDC Service Area Transmission Losses) and the total metered Demand within the UDC Service Area (adjusted for distribution losses). *Id.* If there is a difference, the difference is attributable to meter measurement errors, power flow modeling errors, Energy theft, statistical Load profile errors, and distribution loss deviations. *Id.* In addition, UFE is treated as Imbalance Energy. ISO Tariff, Section 11.2.4.3. It is allocated to each Scheduling Coordinator based on the ratio of its metered Demand (including exports to neighboring Control Areas) within the relevant UDC Service Area to total metered Demand within the UDC Service Area. *Id.* UFE is included in the settlements for Imbalance Energy for each Settlement Period. *Id.*

The inclusion of specific provisions regarding UFE in the ISO Tariff was first proposed by the Joint Commentors in Docket Nos. EC96-19-003 and ER96-1663-003 on June 6, 1997. In response, the ISO included a new definition of UFE as well as provisions regarding the allocation of UFE in its "Restated and Amended Tariff," which it filed on August 15, 1997. In the October 1997 Order, the Commission found that "the ISO Tariff assignment of UFE losses is reasonable." October 1997 Order, 81 FERC at 61,522. The Commission noted that the distribution loss component "should arguably not be assigned" to Scheduling Coordinators that schedule only at the transmission level, but also observed that "quantification of this single component may not be feasible." *Id.* Indeed, prior to the start of operations the ISO considered the idea of differentiating transmission-related UFE from distribution-related UFE. However, it found the cost to achieve this to be prohibitive, because there are over 800 points of Interconnection between the ISO Controlled Grid and the UDC distribution systems. Even so, as discussed below, the calculation of UFE has improved such that little distribution-level UFE is now being incorporated into UFE charges. The Commission made clear in the October 1997 Order that Scheduling Coordinators, including Scheduling Coordinators that schedule only at the transmission level, should bear a share of all other components of UFE "because they are attributable to overall system conditions and do not lend themselves to any reasonable alternative assignment methodology." *Id.*

(2) <u>The UFE Charges That Ran Substantially Higher Than Expected in 1998 and 1999 Were Largely Caused by Transmission-Level, Not Distribution-Level, Errors.</u>

DWR and MWD argue that "UFE costs, which can be substantial, are largely caused by . . . distribution-level functions . . . . " *See* Joint Initial Brief of DWR, MWD, and NCPA at 2-4. This is not true of the UFE charges which ran substantially higher than expected from April through September 1998 and again in the fall of 1999. These charges were largely caused by transmission-level meter data management errors.

In July 1998, the ISO initiated the UFE Project[212] in response to growing Market Participant concern about the magnitude and financial impact of UFE. System UFE was much higher than expected from April through September 1998. It was running between 4% and 6% of total Load and export in the ISO Controlled Grid. Within UDC Service Areas, UFE ranged as high as 15%, and as low as –10%, of total Load and export. The UFE Project ultimately identified significant Generation and Load meter data errors that accounted for about 3 million MWhs and $75 million in UFE charged between April 1 and December 31, 1998. Much of the problem was associated with the submission of Logical meter data by Scheduling Coordinators for the non-Participating TOs. Non-Participating TOs are typically municipalities and federal power marketing agencies with Existing Contracts with Participating TOs. Logical meter data is calculated for the pseudo-Generation and pseudo-Loads used to model and

[212] The goal of the UFE Project was to investigate the unexpectedly high UFE, determine its cause, and fix any identified problem. The ISO worked with all the Scheduling Coordinators on this Project.

schedule Existing Contract power flows to or from non-Participating TOs, for purposes of charging UFE, Imbalance Energy, and other market Settlement costs. This data is derived to accommodate the Existing Contracts of non-participating entities for transmission in the ISO Controlled Grid. Other sources of UFE error in 1998 included erroneous meter data from intra-zonal metering at Midway Substation, and data from a few Generation Units which were improperly mapped in the wrong UDC Service Area, inclusive of one unit at San Onofre Nuclear Generating Station. All these errors were corrected, and Scheduling Coordinators' UFE accounts were adjusted to reflect the corrections. ISO System UFE ran between plus and minus 1% of total Load and export from September 1998 through July 1999.

In addition to discovering UFE errors, UFE Project participants also identified three areas where the calculation and allocation of UFE could be improved. These included (1) an improved model for the calculation of Transmission Losses, (2) more accurate allocation of Transmission Losses among UDC Service Areas, and (3) a methodology to better differentiate transmission-level from distribution-level UFE and allocate it on the basis of cost causation. These issues were subsequently addressed and resolved, as discussed below, in the SIT[213] process with the Market Participants.

First, as a result of the recommendations made in the SIT process, the ISO is improving its calculation of Transmission Losses by replacing its present power flow model with a new one. The software to accomplish this will be installed by the end of 2000. The ISO's present model was derived from WSCC's power flow model and uses scheduled Load. Using scheduled, rather than actual, Load introduces a source for error in the calculation of Transmission Losses. In particular, if scheduled Load is lower than actual Load (as has been the case in the past on the ISO Controlled Grid), Transmission Losses are understated and UFE is overstated. The new ISO power flow model will use real-time power flow data. This change will improve the accuracy of Transmission Losses calculations.

Second, the ISO has implemented a new methodology for the allocation of Transmission Losses that allows it to more accurately allocate Transmission Losses among UDC Service Areas. The new model allocates Transmission Losses, calculated for each transmission line segment, directly to the respective UDC Service Areas. Previously, the ISO calculated total ISO Controlled Grid Transmission Losses and then allocated them among UDC Service Areas, on essentially a pro rata basis.

Third, the SIT participants, including DWR, recommended that each of the three UDCs in the ISO Controlled Grid (i.e., SDG&E, SCE, and PG&E) insert an engineered distribution-related UFE factor into their Distribution Loss Factor, which is charged to the UDC's retail customers in their retail rates. This methodology would effectively move distribution-related UFE from the ISO's overall UFE calculation and apply it directly to retail metered data, i.e., to the rates of the UDC "causing" any distribution-related UFE. The ISO understands

[213] The SIT was established by the ISO to work with Market Participants to resolve concerns about settlement issues.

that SDG&E and SCE have already rolled this “grossed-up” DLF into their retail rates, but that PG&E is still considering implementation, which would require CPUC approval. In summary, MWD should see little distribution-related UFE in its UFE charges and DWR’s portion of its Load in PG&E’s Service Area will see some distribution-related UFE until PG&E receives CPUC permission to “gross up” the DLF.

(3) DWR and MWD Have Little Left to Object to Regarding UFE Charges.

DWR and MWD argue that the ISO should apply cost causation principles in allocating UFE. See Joint Initial Brief of DWR, MWD, and NCPA at 7. DWR and MWD fail to mention that the ISO has taken every opportunity, as described above, to more accurately allocate UFE costs. As a result, DWR and MWD have little left to object to regarding UFE charges. Once all the changes recommended in the SIT process are implemented, UFE charges will include little if any distribution-related UFE. Furthermore, UFE charges should be minimal, unless errors are made. Errors are more likely to be eliminated by increased participation in the ISO. For example, from August 21 through December 31, 1999, the ISO experienced another spike in UFE. The UFE Project team determined that the primary causes were Logical metering difficulties and a transposition of the Load and Generation channels of a replaced transmission substation meter. Logical meter-related errors can be dramatically reduced if non-Participating TOs become Participating TOs, and all Generation and Load meters are read directly. Additionally, “better” allocation methods are not going to affect any future spike in UFE caused by meter data management errors.

(4) The ISO Tariff Requires UFE to Be Calculated for Each UDC Service Area and This is a Reasonable Allocation of UFE.

Proponents argue that "[i]f the ISO intends to use execution of a UDC Agreement as the precondition for reallocating UFE costs among wholesale transmission customers . . . it should make this clear in some sort of FERC filing." Joint Initial Brief of DWR, MWD, and NCPA at 18. Proponents contend that the ISO has made no such filing. *Id.* Proponents are mistaken. Section 4.1.1 of the ISO Tariff provides as follows: "The ISO shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services . . . unless the relevant UDC has entered into a UDC Operating Agreement. The UDC Operating Agreement shall require UDCs to comply with applicable provisions of . . . this ISO Tariff . . . ." At the same time, Section 11.2.4.3 of the ISO Tariff provides that "the ISO will calculate UFE on the ISO Controlled Grid, *for each UDC Service Area*." (Emphasis added). In addition, the definition of UFE in Appendix A of the ISO Tariff reads as follows: "UFE is the difference in Energy, *for each UDC Service Area* and Settlement Period, between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses . . . and the total metered Demand within the UDC Service Area adjusted for distribution losses . . . ." (Emphasis added). Accordingly, it is the ISO Tariff, as currently approved by the Commission, that *requires* the ISO to calculate UFE charges upon a qualified entity becoming a UDC by executing a UDC Agreement.

As this discussion makes clear, UFE is only calculated as provided in Section 11.2.4.3 of the ISO Tariff if the entity in question is treated as a UDC under the Tariff; and an entity is only treated as a UDC under the Tariff if it signs a UDC Agreement with the ISO. These provisions linking calculation of UFE to the signing of a UDC Agreement were set forth in the version of the ISO Tariff submitted to the Commission in August 1997 and approved in October 1997. Thus, this linkage has been "made clear" in a filing with the Commission, as demanded by Proponents.

An entity can qualify as a UDC if it: (1) owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and (2) provides regulated retail electric service to Eligible Customers, and (3) provides regulated procurement service to those End-Use Customers who are not yet eligible for direct access or who choose not to arrange services through another retailer. See ISO Tariff, Appendix A, definition of "UDC."

In order for a qualifying UDC to establish a formal relationship with the ISO, it must enter into a UDC Operating Agreement. See ISO Tariff, Section 4.1.1. Section 4 of the ISO Tariff describes the nature of the relationship between the ISO and UDCs, including UDC Operating Agreements, coordinating Maintenance Outages, UDC responsibilities, System Emergencies, electrical emergency plans, System Emergency reports, coordination of expansion or modifications to UDC facilities, and information sharing. Section 4.1.1 provides that the ISO "shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from the

Distribution System of a UDC directly connected to the ISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement." The UDC Operating Agreement is the vehicle by which the UDC and the ISO agree to reciprocal, enforceable rights, responsibilities, and obligations. The UDC Operating Agreement establishes a contractual relationship between the ISO and the UDC, and requires UDCs to comply with the provisions of Section 4 of the Tariff, other applicable sections of the Tariff, and the relevant ISO protocols. In the absence of Commission action, there is no other way than by contract to bind UDCs to the UDC responsibilities outlined in the Tariff.

The ISO signed UDC Operating Agreements with the three UDCs (i.e., SDG&E, SCE, and PG&E) prior to the ISO Operations Date. Additionally, the ISO unilaterally filed a UDC Operating Agreement for the City of Anaheim prior to the ISO Operators date, and subsequently signed one with the City of Pasadena. In accordance with its Tariff, the ISO has separately calculated UFE for these UDC Service Areas. The ISO has also discussed with Vernon the possibility of its signing a UDC Operating Agreement and, as a consequence, having its UFE separately calculated based upon its own Service Area in accordance with the ISO Tariff. In short, the ISO has been allocating UFE by UDC Service Area since the ISO Operations Date. It has treated every UDC consistently – no matter whether investor-owned or municipally owned, large or small, or old or new to a relationship with the ISO. The ISO's Tariff provision regarding UFE allocation by UDC Service Area is reasonable. Indeed, it implements the cost causation principles otherwise advocated by DWR and

MWD. Nevertheless, DWR and MWD object to this method of allocating UFE, calling it unduly discriminatory. DWR and MWD reveal that one of the primary concerns behind this assertion is their fear that it will shift substantial UFE costs from Vernon to them. *See* Joint Initial Brief of DWR, MWD, and NCPA at 11-12. As shown above, this can fairly be called a phantom fear, particularly given the improvements being implemented in the calculation and allocation of UFE. Today, any UFE for Vernon is included in the Scheduling Coordinator's UDC, which has generally been negative. If Vernon becomes a UDC, the UFE will be specifically calculated for Vernon, and Vernon will incur all costs associated with the UFE.

<u>Cost Causation</u>

As a fallback position, Proponents argue that in any event Market Participants should not need to sign a UDC Agreement to obtain the benefits of the ISO's UFE calculation, because the "mere execution of an agreement" does not alter the amount or allocation of UFE attributable to a Market Participant. Joint Initial Brief of DWR, MWD, and NCPA at 11. Proponents' argument proves too much. Proponents might with equal justification argue that the ISO should extend its services and protections to entities that decline to enter into the agreements necessary to join the ISO, or extend Metered Subsystem treatment to entities that have not signed an appropriate agreement, because the "mere execution" of these agreements does not affect the quality of the electricity provided or any other technical or physical variable on the system. However, the purpose of these agreements is not to work some magical transformation of physical variables, but to regularize and govern the relations between the ISO and its Market Participants, assigning to each a particular set of obligations and entitlements upon which the other party can rely. The same is true with the UDC Agreement. To allow Market Participants to enjoy the benefits bestowed by the UDC Agreement without also taking on the obligations would be unfair and discriminatory to the Market Participants who *have* signed, since it would spread among them the costs of the benefits bestowed upon the non-signing party without a concomitant sharing of burdens by the non-signing party.

Ability to Sign a UDC Agreement

Proponents argue that it is unfair to make the execution of a UDC Agreement a condition for UFE calculation under the ISO Tariff, since entities such as MWD and DWR are ineligible to sign UDC Agreements because they have no distribution functions. They argue that "under the ISO's approach, DWR and MWD cannot avoid the assessment of UFE costs they do not cause *for the very reason that they have no systems that cause such costs.*" *Id.* at 14 (emphasis in original). Proponents ignore the larger picture, however. DWR and MWD have contributed to the UFE calculation imprecisions that imposed costs upon them by using Logical meter data, i.e., pseudo-Load and pseudo-Generation to model and schedule power flows, as discussed previously above. Thus, DWR and MWD cannot claim that their operations have not contributed to the UFE issues of which they complain. Another answer to their argument is that, as also demonstrated above, the ISO has now adjusted its UFE calculation to minimize distribution-related UFE. Under this new regime, non-wholesale UFE should be very small and does not justify dismantling the ISO's system concerning the treatment of UDCs and UFE.

Conclusion

The ISO's UFE charges are just and reasonable, consistent with the ISO Tariff, in compliance with the FPA, and not unduly discriminatory. Proponents' objections should be dismissed.

O.2. With respect to operating instructions:

a. Whether Section 2.4.4.4.1.1 of the ISO Tariff improperly provides for default to the Participating TO's operating instructions to the ISO for an Existing Contract when those instructions are disputed by the party or parties to the Existing Contract, and whether Sections 7.1.1, 7.3.1 and 7.4.1 of the Scheduling Protocol should provide for information regarding Existing Contracts to be set forth in the operating instructions to be developed jointly by the Responsible Participating Transmission Owner and the Existing Contract rights holder? [Issue No. 644, Docket Nos. EC96-19-009 and ER96-1663-010. Proponents - TANC, Cities / M-S-R, and Palo Alto]

Section 2.4.4.4.1.1 of the ISO Tariff provides in relevant part as follows:

> In the event that the parties to the Existing Contract cannot agree upon the operating instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the Participating TO's operating instructions.

A number of parties argue that this provision is unfair and unreasonable. TANC contends that the default provision provides no incentive for the Participating TO to resolve the dispute. TANC instead recommends that in the event of a dispute, the prior operating procedures applicable to the Existing Contract should be implemented. Joint Initial Brief on Issues O.2.a, O.2.c, and

O.11, at 4-5. TANC further contends that the Commission may be powerless to award retroactive relief or provide redress to the Existing Rights holders for any damages incurred during a protracted dispute resolution process. *Id.* at 5. These arguments are without merit. As discussed above in relation to Issue C.5, this provision is appropriate and necessary. During the dispute resolution process, the ISO must continue to provide consistent service. The Commission has agreed, finding that it was reasonable for the ISO to rely on the operating instructions of the Participating TO because the Participating TO is the party most familiar with performing the operating instructions under the Existing Contract, and is also the party with which the ISO has a contractual relationship. *See* October 1997 Order, 81 FERC at 61,473. In addition, the Commission has rejected TANC's recommendation to implement prior operating procedures in the event of a dispute as unworkable. *Id.* TANC does not provide any information to support that its assertion that this unworkable proposal has now become feasible.

TANC contends that Sections 7.1.1, 7.3.1, and 7.4.1 of the SP should be amended to include Existing Rights holders in the process to provide instructions to the ISO for schedule validation. *See* Joint Initial Brief on Issues O.2.a, O.2.c, and O.11, at 3-4. The ISO disagrees. As with respect to the default provision of Section 2.4.4.4.1.1, it is reasonable to have one point of contact – the Participating TO – submit the instructions to the ISO that the ISO will use to validate Schedules for Existing Contracts.

b. <u>Whether the authority granted the ISO under its Tariff to control facilities of a Utility Distribution Company or Metered Subsystem is excessive and inconsistent with the terms and conditions of Existing Contracts, and whether the ISO's authority to approve or cancel outages, over metering standards and with respect to Operation & Management practices, which is different from or additional to the standards reflected in Existing Contracts, is unreasonable? [Issue No. 646, Docket Nos. EC96-19-009 and ER96-1663-010. Proponent - TANC]</u>

In the October 1997 Order, the Commission rejected proposals to limit the ISO's authority to control facilities making up the ISO Controlled Grid and resources upon which it relies to ensure the reliability of the ISO Control Area. With respect to Ancillary Services provided by a Metered Subsystem, the Commission stated as follows: "We agree that the ISO, as the single Control Area Operator, needs real time dispatch rights over all resources committed to provide Ancillary Services." October 1997 Order, 81 FERC at 61,496. More generally, the Commission approved as reasonable "the requirement that participants comply with all ISO orders except those that would result in impairment to public health or safety." *Id.* at 61,456. This requirement is essential, the Commission explained, because "otherwise the ISO will be unable to effectively manage and control the ISO Controlled Grid." *Id.*at 61,456-57.

TANC contends that certain unidentified provisions of the ISO Tariff, the ISO protocols, and *pro forma* agreements applicable to Metered Subsystems and UDCs give the ISO excessive control over the facilities of those entities and may conflict with provisions of Existing Contracts. TANC asks the Commission to "direct the ISO to propose revisions to its Tariff and Protocols to eliminate all provisions applicable to UDCs and MSSs that conflict with the terms of Existing

Contracts." Initial Brief of TANC at 17. TANC fails, however, to identify any particular provisions of the ISO Tariff or protocols that create this concern. Neither does it identify the terms of any Existing Contract with which the ISO Tariff or protocols conflict or explain the nature of the alleged conflict. It simply states that conflicts exist "in many respects," without identifying any of them. *Id.* at 16.

These opaque statements plainly present an insufficient basis for the Commission to reconsider its rulings in the October 1997 Order. They also provide nothing to which the ISO may respond. TANC would have the ISO, and then the Commission, attempt to divine the specific nature and basis of TANC's concerns. That, however, is TANC's job. Because TANC has not provided any detail to support its objections to undisclosed provisions of the ISO Tariff and protocols due to undescribed conflicts with unidentified provisions of unnamed Existing Contracts, the Commission should reject those objections. Moreover, as noted in connection with Issue E.1, the ISO recently filed its Metered Subsystem proposal in Amendment No. 27. To the extent that TANC continues to have an objection, it may raise the objection in that matter.

c. Whether Section 2.3.1.2.1 of the ISO Tariff should be amended to limit the authority of the ISO to impose its operating orders on all Market Participants where no such authority derives from Existing Contracts or arrangements or where such orders are in direct conflict with the operating procedures of a Utility Distribution Company or the terms and conditions of an Existing Contract? [Issue No. 668, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponents - TANC, Cities / M-S-R, and Palo Alto]

Proponents claim that Section 2.3.1.2.1 of the ISO Tariff allows the ISO to exercise authority over Market Participants in a manner that is inconsistent with the terms of Existing Contracts. Joint Initial Brief on Issues O.2.a, O.2.c, and O.11, at 2. Proponents contend that the ISO's authority to administer an Existing Contract should be limited to the operating instructions submitted to the ISO by the Participating TO pursuant to Section 2.4.4.4.1.1. Existing Rights holders should thus be exempt from conflicting operating orders that apply to Market Participants that are not parties to Existing Contracts. *Id.* at 7-8. In order to accomplish this, Proponents request that the Commission order the ISO to revise Section 2.3.1.2.1 to exempt all Market Participants within the ISO Control Area from operating orders that are in direct conflict with a UDC's established procedures or are inconsistent with the terms and conditions of an Existing Contract. *Id.* at 8.

Proponents' contention is baseless and the requested revision is unnecessary. The ISO has committed to honor the terms of Existing Contracts. The only exception to this commitment is a situation where the ISO must issue instructions in order to maintain grid reliability. Sections 5.1.3 and 5.6 of the ISO Tariff provide for the ISO to assume supervisory control over all Generating Units and System Resources to maintain reliability of the ISO Controlled Grid during a System Emergency and in circumstances in which the ISO considers a System Emergency to be imminent or threatened. Therefore, Section 2.3.1.2.1 does not impede the functioning of Existing Contracts.

The Commission supports the ISO's assuming temporary authority in emergency situations. In its October 1997 Order, the Commission noted that "[i]n an emergency, the ISO needs to be certain that its operating instructions will be followed." October 1997 Order, 81 FERC at 61,571. Likewise, in its recent order on RTOs, the Commission concluded that for reliability purposes, the RTO must have full authority to order the Redispatch of any Generator connected to the transmission facilities it operates to prevent or manage emergency situations.[214] Proponents' claim is unfounded and should therefore be rejected.

Consequently, Proponents' suggested changes to Section 2.3.1.2.1 are unnecessary and could increase the risk of System Emergencies and reliability problems. These changes should thus be rejected.

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[214] Order No. 2000, FERC Stats. and Regs., Regs. Preambles ¶ 31,089, at 31,104.

O.3. Whether sections 2.3.1.2.2, 2.3.1.3.1, 5.1.1, and 5.6.1 should be revised to restrict the ISO's ability to give operational instructions to generation located outside of the ISO Control Area. [Issue No. 635, Docket Nos. EC96-19-001 and ER96-1663-001. Proponents - BPA and CAC]

In its initial comments on the ISO's Tariff submissions, BPA recommended that the Commission require the ISO to clarify the Tariff so that only Market Participants within the ISO Control Area are made subject to the ISO's Operational Control. *See* October 1997 Order, 81 FERC at 61,512. According to BPA, Sections 2.3.1.2.2, 2.3.1.3.1, and 2.3.2.1 of the ISO Tariff improperly afforded the ISO broad authority over all Market Participants. *Id.* In response, the Commission stated that it

> disagree[d] with BPA that Sections 2.3.1.2.2, 2.3.1.3.1, and 2.3.2.1 of the ISO Tariff need to be clarified to provide that the ISO will not have control of the resources of Market Participants outside of the ISO Control Area. To the extent that a Market Participant outside of the ISO Control Area is providing energy, dispatchable load or ancillary services, those resources must follow the operating instructions of the ISO.

Id. at 61,513.

Unresolved Issue No. 635 originated as a rehearing request filed by BPA of the Commission's October 1997 Order. BPA, however, did not seek to pursue this issue by filing a initial brief in this proceeding. Instead, EPUC/CAC seeks to utilize this issue to raise a new and unfounded assertion that QF facilities located *within* the State of California and directly interconnected to the systems of Participating TOs are not part of the ISO's Control Area.

EPUC/CAC repeats its assertions that QF operations were not contemplated in the ISO Tariff and that the ISO is improperly seeking to impose requirements on Loads served by QF generators. Joint Initial Brief on Issue O.3, at 4. The ISO has demonstrated in prior sections of this initial brief (see for example the discussion concerning Issue A.3.a) that these assertions are incorrect. For example, Section 5.1.5 of the ISO Tariff, concerning "Existing Contracts for Regulatory Must-Take Generation," states as follows:

> Notwithstanding any other provision of this ISO Tariff, the ISO shall discharge its responsibilities in a manner which honors any contractual rights and obligations of the parties to contracts, or final regulatory treatment, relating to Regulatory Must-Take Generation of which protocols or other instructions are notified in writing to the ISO from time to time and on reasonable notice.

Moreover, the ISO disagrees with EPUC/CAC that the issue of whether QFs directly connected to the systems of Participating TOs are part of the ISO Control Area is pending in Docket Nos. ER98-997-000 and ER98-1309-000. Joint Initial Brief on Issue O.3, at 5. Attachment 2 contains the testimony of CAC that has been filed in the QF PGA case. This testimony contains no discussion of this issue. To the contrary, the only issues identified by CAC in its testimony are: (1) only the Cogenerator's output which is available to fully participate in the market like a merchant plant, should be subjected to the ISO Tariff and protocols; (2) the Cogenerator must be allowed greater flexibility in the scheduling of outages; (3) the ISO should not be permitted, by amending its Tariffs and protocols, to amend unilaterally the PGA negotiated with a Cogenerator; and (4) the Cogenerator should be allowed to terminate its PGA without Commission approval.[215]

EPUC/CAC concedes that "there can be no question that the Control Area extends throughout the geographic locations that comprise the transmission system operations that it has been authorized to operate." Joint Initial Brief on Issue O.3, at 5. With regard to QF operations, however, EPUC/CAC contends

215 See Prepared Direct Testimony of James A. Ross on Behalf of the Cogeneration Association of California, Docket Nos. ER98-992-000, *et al.* (filed Oct. 20, 1998), at 2. Docket Nos. 98-997-000 and ER98-1309-000 were later severed from the primary PGA docket.

that the Control Area "boundaries are the metering points of interconnection at the site boundary of the QF Operation." *Id.*

As noted above in relation to Issue F.2, EPUC/CAC's assertion that the ISO's right to monitor generator performance should not extend beyond the Interconnection point between the generator and the ISO Controlled Grid was explicitly rejected by the Commission in the October 1997 Order. The Commission stated: "We find the restrictions proposed by EPUC/CAC to be inappropriate and unworkable. Restricting the right to monitor to the point of interconnection will severely restrict the acquisition of any meaningful information on generation performance particularly with respect to ancillary services." October 1997 Order, 81 FERC at 61,514. EPUC/CAC never sought rehearing of this determination and should not be able to reargue this issue in this docket.[216]

WSCC defines a Control Area as an area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange with other control areas, and contributing to frequency regulation of the interconnection. WSCC Minimum Reliability Criteria, March 1999. As the Control Area operator, the ISO is required, in accordance with NERC and WSCC criteria, to do the following:

(1) match, at all times, the power output of Scheduling Coordinators' Generating Units within the ISO electric power system, plus the Energy imported by Scheduling Coordinators from entities located beyond the ISO's points of interchange with adjoining Control Areas, with Scheduling Coordinators' Demand within the ISO electric power system;

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

[216] *See Transcontinental Gas Pipe Line Corporation*, 66 FERC at 61,764 ("[Proponent's] . . . request, which it styled a request for clarification, was simply an attempt to circumvent the statutory provisions for rehearing. This the Commission will not allow.").

(3) maintain the frequency of the ISO electric power system within reasonable limits, in accordance with Good Utility practice; and

(4) provide sufficient generating capacity to maintain Operating Reserves in accordance with Good Utility Practice*.*

Interconnected QF operations are part of the ISO's Control Area responsibility. For example, the ISO's Load responsibility establishes the ISO's Ancillary Services requirements. WSCC defines load responsibility as "a Control Area's firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the Supplier." *Id.* When a QF unit trips off and the Load being served by that facility is not instantaneously disconnected from the ISO Controlled Grid, the added system Demand has effects on the ISO's system.

For example, assume a QF is serving an on-site industrial facility with a Load of 25 MW. Assume also that an unexpected event occurs and the QF's generator is shut down. The ISO's ACE then changes by this 25 MW amount (plus the changes in system losses that will have occurred due to the disconnection of the generation). At the scan rate of the ISO's EMS, Participating Generators providing Regulation (i.e., enabled Automatic Generation Control) would be issued control signals to adjust their output for the 25 MW deficiency. To return the Regulation units to their preferred operating points, the ISO would then call on resources, in price merit order, from the real-time Imbalance Energy market. Assuming further that the QF had its Generation Unit monitored by the ISO's EMS, the ISO would have also detected the cause of the ACE excursion. On the other hand, if the QF did not have its Generating Unit monitored by the ISO's EMS, the disconnection of the generation would still have caused ACE to change by the same amount; the only difference would be that the ISO would not have any information on what event occurred or where it occurred (unless the QF's operators provided the information to the ISO Control Area operators).

Previously, EPUC/CAC has recognized that QF standby arrangements utilize the ISO Controlled Grid:

> Requiring a customer to "reserve" through Standby Service a particular level of transmission access simply does not comport with the proposed open access transmission framework contemplated in the Phase II Filings. Under the new access rules, transmission capacity cannot be reserved; access is rationed on a daily basis using congestion protocols. Moreover, the obligation to provide transmission access no longer rests with the local distribution utility, but with the ISO.[217]

Outages at QF units have direct effects on the ISO Controlled Grid. The ISO must procure reserves to meet outages at QF units as well as at non-QF generators. Accordingly, the ISO respectfully requests that the Commission continue to find that EPUC/CAC's assertion that the ISO Controlled Grid should not extend beyond the Interconnection point between the Generator and the ISO to be "inappropriate and unworkable." The adoption of EPUC/CAC's proposal would result in cost shifts to other Market Participants who would incur the costs of the Ancillary Services needed to support the QF Loads.

[217] Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California, Docket Nos. EC96-19-003 and ER96-1663-003 (June 6, 1997), at 28 (citations omitted).

O.4. Are ISO Tariff section 2.5.20.5.1 and SP Sections 3.2.6.3, 3.2.8.3, and 3.3.1.3 which result in the invalidation of a submittal for all Settlement Periods for the relevant Trading Day if the submittal for any one Settlement Period is invalid, just and reasonable, and is Settlement and Billing Protocol 3.4, which provides that a Scheduling Coordinator error in the denomination of the reference number for an Existing Contract results in the entire Schedule being treated as a new firm use, consistent with the ISO Tariff's obligation to honor Existing Contracts as stated in sections 2.4.3 and 2.4.4? [Issue No. 12, Docket Nos. EC96-19-006, EC96-19-008, ER96-1663-007, and ER96-1663-009, and Issue No. 659, Docket Nos. EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, EC96-19-009, ER96-1663-001, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, and ER96-1663-010. Proponents - BPA, Southern Cities, TANC, Dynegy, MWD, and DWR]

Proponents argue that "[t]he ISO's invalidation of Schedules for an entire day due to an error in a single hour unreasonably exposes Scheduling Coordinators and Existing Rights holders to increased costs." Joint Initial Brief on Issue O.4, at 1-2. Proponents refer to ISO Tariff provisions as indicating that a "Scheduling Coordinator error in the designation of information for the self-provision of Ancillary Services in a Day-Ahead Schedule for any one hour shall invalidate the Schedule for the entire day," (*id.* at 3) and that "a Scheduling Coordinator error in the denomination of the reference number for an Existing Contract would result in the Schedule being treated as a new firm use" (*id.* at 5). Proponents "urge the Commission to order the ISO to develop alternative and less punitive methods for addressing technical errors in the scheduling process." *Id.* at 2.

Proponents' positions appear to be based upon a misunderstanding of the ISO's scheduling capabilities, including the available opportunities for correcting errors. In fact, the impacts flowing from a Scheduling Coordinator's failure to submit correct Schedule information are unavoidable consequences of the Day-Ahead scheduling process itself. Because of software and other limitations, the ISO is able to deal with Day-Ahead Ancillary Services and Energy Schedules in full-day increments only. Thus, errors as to one part of a day's Schedule will necessarily require the ISO to invalidate the entire Schedule.[218]

Similarly, submission of an erroneous reference number provides the ISO with input that its software and procedures interpret as a new firm transmission request. Contrary to Proponents' assertions, this is not intended to be "punitive" or "draconian"; rather, it is a consequence of the fact that the ISO is obligated to accept the Scheduling Coordinators' transmission requests as they are forwarded to it. The ISO has no basis on which to "correct" such reference numbers, and it would be an unreasonable burden on the ISO to require it to chase down such corrections. The Commission has recognized this:

> Metropolitan argues that this procedure should be rejected because Existing Rights holders will be exposed to the risk of additional costs that are not warranted under their Existing Contracts solely due to a Scheduling Coordinator error. Our analysis indicates that the ISO's proposal represents a necessary and orderly validation procedure that reasonably places the burden of properly identifying Existing Contract rights on the Scheduling Coordinators. Therefore, it is appropriate to hold the Scheduling Coordinators responsible for following the proposed validation procedure.

California Independent System Operator Corporation, 83 FERC ¶ 61,209, 61,922 (1998). The validation procedure referred to is that provided by Section 2.2.7.2

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[218] Furthermore, even if the ISO's software and procedures could accommodate fractional-day changes, without input from the erring Scheduling Coordinator the ISO would be unable unilaterally to provide corrections to the Schedule. Under such a regime, it would place too great a burden on the ISO to chase down corrections of erroneous Schedules while in the process of scheduling and Dispatching the California transmission system. It makes more sense to place the burden of providing correct Schedules on the Scheduling Coordinators, whose job it is to submit correct Schedules, rather than on the ISO.

of the ISO Tariff, which gives Scheduling Coordinators until the applicable scheduling deadline to validate their Schedules. This is an added protection – which applies to both of the types of errors identified by Proponents – for Scheduling Coordinators, and allows them to insulate themselves from the consequences of erroneous Schedule submittals. Should a Scheduling Coordinator fail to protect itself by utilizing this procedure, the ISO does not believe that the Scheduling Coordinator should be able to complain of the consequences. And, while they were not intended as such, these consequences provide appropriate incentives for Scheduling Coordinators to ensure that they submit correct Schedule information to the ISO.[219]

For the foregoing reasons, the ISO respectfully requests that the Commission deny Proponents' proposal that the ISO be directed to modify its scheduling process to accommodate Proponents' concerns.

O.5 <u>Should ISO Tariff section 5.1.4 be modified to increase the size of the threshold exemption for Generating Unit compliance with section 5 (other than in System Emergencies)? [Issue No. 653, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, EC96-19-009, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, ER96-1663-010 OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponents - MWD, Cities / M-S-R, and Palo Alto]</u>

Section 5 of the ISO Tariff states that the ISO shall not be obligated to accept Schedules or Adjustment Bids from any Generating Unit interconnected to the ISO Controlled Grid unless the Generator undertakes in writing to comply

[219] In their initial brief, Proponents refer to "the ISO's representations that it will ensure that Existing Rights are honored and will not invalidate Existing Contract schedules due to erroneous contract reference numbers." Joint Initial Brief on Issue O.4, at 6. The ISO clarifies that the validation procedures that it has put in place should enable Scheduling Coordinators to protect Existing Rights from invalidation. However, it is the Scheduling Coordinators' responsibility to use these procedures to ensure such protection, as the Commission has recognized. *See California Independent System Operator Corporation*, 83 FERC at 61,922.

with the ISO Tariff. Section 5.1.1 requires that Participating Generators shall cause their facilities to be operated in accordance with the provisions of the ISO Tariff. Section 5.1.2 similarly requires compliance with the ISO's protocols. Section 5.1.3 is a critical provision that covers actions for maintaining the reliability of the ISO Controlled Grid:

> The ISO plans to obtain the control over Generating Units that it needs to control the ISO Controlled Grid and maintain reliability by purchasing Ancillary Services from the market auction for these services. When the ISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Ancillary Services bids it has received to respond to the operating event and maintain reliability. Only when the ISO has used the Ancillary Services that are available to it under such Ancillary Services bids which prove to be effective in responding to the problem and the ISO is still in need of additional control over Generating Units, shall the ISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a real-time system problem or emergency condition could be in existence or imminent.
>
> Each Participating Generator shall take, at the direction of the ISO, such actions affecting such Generator as the ISO determines to be necessary to maintain the reliability of the ISO Controlled Grid. Such actions shall include (but are not limited to):
>
> (a) compliance with the ISO's Dispatch instructions including instructions to deliver Ancillary Services in real time pursuant to the Final Day-Ahead Schedules and Final Hour-Ahead Schedules;
>
> (b) compliance with the system operation requirements set out in Section 2.3 of this ISO Tariff;
>
> (c) notification to the ISO of the persons to whom an instruction of the ISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and
>
> (d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the ISO in a manner that ensures that the ISO will have the ability, consistent with this ISO Tariff and the ISO Protocols,

> to direct the operations of the Generator as necessary to maintain the reliability of the ISO Controlled Grid.

Section 5.1.4 provides a limited exemption:

> A Participating Generator with a Generating Unit directly connected to a UDC system will be exempt from compliance with this Section 5 in relation to that Generating Unit, other than Section 5.6 (System Emergencies) provided that (i) the output of the Generating Unit is less than 10 MW, and (ii) the total output is sold to the interconnecting UDC or to customers connected to the UDC's system. Any such Participating Generator shall comply with applicable UDC tariffs, interconnection requirements and generation agreements. This exemption in no way affects any obligation to pay the appropriate Access Charges or to comply with all the other applicable Sections of this ISO Tariff.

Proponents argue that the size limitation should be increased to 20 MW. Joint Initial Brief on Issue O.5, at 2. They contend that an increase in the Generating Unit exemption established under Section 5.1.4 would encourage broader participation by smaller units. *Id.* at 4. Proponents also note that the ISO has instituted a competitive procurement process for LARS, to determine whether lower-cost alternatives to current Reliability Must-Run Generation exist, and to select the alternatives that best meet the ISO's reliability concerns. *Id.* at 5. They cite the fact that for the LARS 2000 process, the ISO found it convenient to recommend increasing the minimum capacity standard from 10 MW to 20 MW, as supporting the contention that

> [s]ince the ISO has determined that it would be impractical to administer contracts and dispatch instructions for a multitude of smaller units, existing communication facilities and procedures for Generating Units 20 MW or less should provide the ISO with entirely adequate means to meet Applicable Reliability Criteria or to relieve System Emergencies.

Id. at 6.

The ISO disagrees that the maximum MW size of plants entitled to the exemption from compliance with Section 5 of the ISO Tariff should be increased from 10 MW to 20 MW. As discussed above with respect to Issue B.5.a, it is reasonable for the ISO to require execution of a PGA for Generating Units whose output uses the ISO Controlled Grid or is sold into the ISO's markets. The PGA covers such matters as certification requirements and data collection requirements relating to major incidents, including System Emergencies and problems that affect System Reliability. The PGA includes an acknowledgment that the reliability of the ISO Controlled Grid depends on the Participating Generator's compliance with the ISO Tariff. Thus, the PGA is an agreement that addresses both a Generating Unit's participation in the ISO's markets and its role in the ISO's operation of the ISO's Control Area in a safe and reliable manner in accordance with Good Utility Practice and applicable standards for Control Area operation.

The communications requirements play an important role in the ISO's performance of its responsibilities as the Control Area operator. For example, the ISO uses telemetry from Generators within the Control Area to determine its reserve responsibility. The ISO also adds the sum of generator output within its Control Area to its net interchange (either positive or negative) with interconnected Control Areas to determine the current level of Load being served. To the extent that Generators within the Control Area do not provide the ISO with telemetry on their output, this calculation becomes less precise. Such a problem may arise from the cumulative effect of numerous small generators failing to provide this information in real time.

In connection with Issue F.1, the ISO explained that its metering and communications typically do not present an undue burden, but in a case-specific situation a Market Participant could seek an exemption if compliance with the standards would be unreasonable. The ISO cited testimony filed in Docket No. ER98-1499-000 by Mr. Mark Morosky, the ISO's Manager of Metering and MDAS

Operations, which explained the following with respect to the costs of compliance with the ISO's metering requirements: (1) the ISO certified meter costs approximately $2,500; (2) installation costs will vary for different facilities;[220] (3) independent third-party inspection by a certified ISO Metering Inspector should cost approximately $1,000; and (4) ISO communications circuit and networking equipment lease costs are approximately $240 per month. These last costs are likely to decrease as the ISO develops secure techniques to poll the meters over the Internet. Indeed, the ISO has recently notified Market Participants that it was implementing a stakeholder process regarding its proposal to develop a set of standards and requirements for installation of direct telemetry to the ISO's EMS from all Generating Units providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, or Supplemental Energy, other than those providing Regulation.

If the ISO's data and communication requirements present an unreasonable burden for a particular Generator, Section 13 of the MP outlines a process by which applicants can request and the ISO will consider requests for either temporary or permanent exemptions from the ISO's metering requirements where compliance with the requirements would be unnecessary, impractical, or uneconomic. In evaluating whether or not to grant an exemption, the ISO considers such factors as: (1) does the exemption request compromise the accuracy and integrity of the meter data or system; (2) does the exemption affect the speed or integrity of the communication system; (3) are the ISO requirements

[220] Factors may include the configuration of the unit and whether or not the Generator can undertake the work itself. For facilities that rely on internal engineering resources for the electrical work, and for the preparation of the design documents and schematics, the costs for installation and configurations can be limited to the cost of existing engineering staff time. If a Generator relies solely on engineering consultants, the cost may be higher, depending on the specifics of the contract. The ISO will assist in providing technical support, further decreasing installation costs.

unnecessary, impractical, or uneconomic for the ISO Metered Entity; and (4) whether the request is for a temporary or a permanent exemption.[221]

Also in relation to Issue F.1, the ISO explained the need for uniformity in its data collection and communication requirements. The ISO cited the following testimony of Ms. Deborah A. Le Vine, the ISO's Director of Contracts & Compliance (also from Docket No. ER98-1499-000):

> The ISO believes that metering requirements should be applied, to the extent feasible, in a uniform, non-discriminatory manner. . . . Such an approach facilitates the automation of the ISO's settlement and billing process. Automation of the meter data prevents shifting of administrative costs to participants that comply with the ISO's metering requirements from those facilities that do not. If the unit does not supply settlement quality data to the ISO or allow for direct polling in accordance with the ISO's metering standards, it causes the ISO to perform manual "work arounds" which are time consuming and resource intensive.[222]

As Ms. Le Vine further explained,

> Currently, the ISO processes almost 600,000 settlement line items per month for approximately 20 million MWH per month of transactions with gross billings of between $200 to $650 million. The ISO has been working to automate settlement entries, including metering, and the validation process. Given the volume and complexity of the transactions and the need to ensure timely and accurate settlements, the ISO must require uniform standards for gathering and reporting of metering data.[223]

Finally, Proponents' reference to the ISO's LARS process is inapposite. The fact that Generating Units must be of a sufficient size to provide local area reliability service does not diminish the ISO's need for timely and accurate

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[221] Prepared Direct Testimony of Mark Morosky on Behalf of the California Independent System Operator Corporation, Docket Nos. ER98-1499-000, *et al.* (filed Feb. 19, 1999), at 7-8.

[222] Prepared Supplemental Direct Testimony of Deborah A. Le Vine on Behalf of the California Independent System Operator Corporation, Docket Nos. ER98-1499-000, *et al.* (filed Feb. 26, 1999), at 4.

[223] *Id.* at 9.

information from smaller Generating Units operating within the ISO Control Area. The requirements of Section 5 of the ISO Tariff are reasonable. If a hardship is presented for a specific facility, the owner of that project may seek an exemption in accordance with the criteria contained in the ISO Tariff.

O.6. Do ISO Tariff sections 5.2.7.1 and 5.2.7.2 require the unduly burdensome posting of financial security, thereby causing those Transmission Owners responsible for must-run payments to bear unnecessary costs? [Issue No. 639, Docket Nos. EC96-19-013 and ER96-1663-014. Proponent - Southern California Edison Company ("SoCal Edison")]

This issue has been withdrawn. Joint Initial Brief of PG&E and SCE on Issue O.14, at 1.[224]

O.7. Whether the protection afforded tax exempt debt should apply to debt issued after December 20, 1995? [Issue No. 664, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponents – Cities / M-S-R and Palo Alto]

Section 2.3.3 of the TCA provides that nothing in the TCA "shall compel any Participating TO or Municipal Tax-Exempt TO which has issued Tax-Exempt Debt to violate restrictions applicable to transmission facilities financed with Tax-Exempt Debt or contractual restrictions and covenants regarding use of transmission facilities *existing as of December 20, 1995*." (Emphasis added.) This provision was included in the TCA because it is required under AB 1890.[225] By mandating the provision, the California Assembly was expressing its clear

[224] In addition, the ISO understands that the reference to Issue B.6 in the footnote on the above-cited page is a typographical error; the reference should be to Issue C.6.

[225] *See* AB 1890, Section 12 (quoting California Public Utilities Code, Section 9600(a)(6)).

intent that the grandfathering of protection for certain tax-exempt financed facilities should have defined limits. Cities/M-S-R acknowledges this, but it nevertheless insists that the Commission should disregard the intent of the California Assembly and delete the words "existing as of December 20, 1995."[226]

Nevertheless, the ISO believes that a compromise on this issue can be reached. The phrase "existing as of December 20, 1995" can reasonably be interpreted to mean "existing but not necessarily in service as of December 20, 1995."[227] This interpretation should permit the Mead-Adelanto transmission project to be grandfathered, as Cities/M-S-R desires. See Initial Brief of Cities/M-S-R at 23-24.

O.8. Whether the definitions of Regulatory Must Take Generation and Eligible Regulatory Must-Take Generation should be modified to ensure that all Must-Take units receive comparable treatment? [Issue No. 665, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponents – Cities / M-S-R and Palo Alto]

Cities/M-S-R asserts that

> [u]nder the Overgeneration provisions of the ISO Tariff, a Generator enjoys certain benefits in terms of curtailment priority if it is deemed to be "Regulatory Must-Take Generation" or "Eligible Regulatory Must-Take Generation." The current definitions of those two terms preclude certain Generators from obtaining those benefits unless (1) the owner of such Generator has provided direct access to its End-Use Customers and (2) the owner serves load in the ISO

[226] *See* Initial Brief of Cities/M-S-R at 22-24. In addition, Cities/M-S-R claims that the provision "improperly denies tax-exempt entities the benefits they enjoy as a result of federal law." *Id.* at 23. However, Cities/M-S-R does not provide any legal precedent to support its claim.

[227] The California Assembly could easily have specified that an existing facility is one that is in service, but declined to do so.

> Control Area. These two limitations are improper. . . . Additionally the Cities/M-S-R propose . . . to expand the definition of Regulatory Must-Take Generation to enable all units with minimum take and minimum fuel-burn obligations to qualify . . . .

Initial Brief of Cities/M-S-R at 5-6. Cities/M-S-R provides the following as examples of Generation they would like to bring within the Regulatory Must-Take definitions: (1) plants with long-term, take-or-pay type fuel contracts and (2) purchases of take-or-pay Energy from third-party Generators. *Id.* at 25. Finally, Cities/M-S-R contends that

> there is an improper limitation in the definition of "Regulatory Must-Take Generation" that the eligible power purchase contracts be "pre-existing" contracts. If a Market Participant deems it economically and operationally beneficial to enter into a power purchase agreement in the future with minimum-take provisions, it should be allowed to do so without risking adverse treatment under the ISO Tariff.

Id. at 28. Thus, Cities/M-S-R contends that the requirement that only Existing Contracts can come under the Regulatory Must-Take definitions should be removed from the ISO Tariff.

Cities/M-S-R's contentions and proposals appear to stem from factual misunderstandings and a misapprehension of the policies underlying the Regulatory Must-Take definitions. The ISO addresses these below.

(1) <u>Cities/M-S-R Misunderstands the Operation of the Regulatory Must-Take Definitions.</u>

Cities/M-S-R's contention that "[u]nder the Overgeneration provisions of the ISO Tariff, a Generator enjoys certain benefits in terms of curtailment priority if it is deemed to be 'Regulatory Must-Take Generation' or 'Eligible Regulatory Must-Take Generation'" *(id.* at 5) is simply inaccurate. While such a preference was contained in these provisions at one time, the current version of Section 2.3.4 of the ISO Tariff, which sets forth the steps to be followed by the ISO to mitigate Overgeneration conditions in real time, contains no reference at all to Must-Take Generation. While Cities/M-S-R is correct that Section 5.1.5 of the ISO Tariff provides that "the ISO shall discharge its responsibilities in a manner which honors any contractual rights and obligations of the parties to contracts, or final regulatory treatment, relating to Regulatory Must-Take Generation . . .", it is not specified that this more general provision will result in the kind of curtailment priority that concerns Cities/M-S-R.

Cities/M-S-R also misunderstands another aspect of the operation of the Regulatory Must-Take definitions within the ISO Tariff. Cities/M-S-R contends that "[t]he current definitions of those two terms preclude certain Generators from obtaining those benefits unless (1) the owner of such Generation has provided direct access to its End-Use Customers and (2) the owner serves load in the ISO Control Area." *Id.* at 5-6. However, as Cities/M-S-R recognizes later in its initial brief, this definition actually applies only to Eligible Regulatory Must-Take Generation. *Id.* at 27; *see* ISO Tariff, Appendix A, definition of "Eligible Regulatory Must-Take Generation." However, since the only provision of the ISO Tariff which Cities/M-S-R is able to cite in support of its contention that the Tariff favors Must-Run Generation is Section 5.1.5, and because Section 5.1.5 refers only to Regulatory Must-Run Generation (rather than the distinct category of *Eligible* Regulatory Must-Run Generation), it follows that the Tariff's definition of Eligible Regulatory Must-Run Generation is irrelevant to Cities/M-S-R's argument. That is, any benefits of concern to Cities/M-S-R accruing to Must-Take Generation are afforded to Regulatory Must-Take Generation. Regulatory Must-Take Generation is defined as "those resources, identified by the California Commission or other Local Regulatory Authority, that will not be subject to competition." October 1997 Order, 81 FERC at 61,523. They include such resources as QF and nuclear generators. *Id.*

(2) <u>The Contracts Identified By Cities/M-S-R Should Not Come Under the Regulatory Must-Take Definitions.</u>

The presumption under the ISO Tariff and the Commission's orders relating thereto is that transactions taking place in the ISO's Control Area will be subject to the competitive markets contemplated in the ISO Tariff unless they are governed by Existing Contracts,[228] or unless some other compelling policy requires that they be removed from the competitive markets. In particular, the treatment accorded by Section 5.1.5 of the ISO Tariff to Generation such as QFs and nuclear units – i.e., their being rendered "not subject to competition" – is accorded because of the special regulatory and technical status of these types of Generation. Thus, the state and federal regulatory policies favoring fuel diversity and Energy independence underlying PURPA[229] require that the Energy

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[228] As described in the October 1997 Order:

> To the extent that an entity concludes that the benefits and obligations of ISO membership do not warrant giving up its existing rights, that entity may continue to exercise its existing rights for the term of its contract. However, if such an entity decides that the benefits of ISO membership are greater than those under its existing arrangements, that entity should be prepared to operate according to the ISO's established practices and rules.

October 1997 Order, 81 FERC at 61,471.

[229] Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in sections of 15 U.S.C, 16 U.S.C., and 43 U.S.C.).

contracts entered into by PURPA QFs, which provide the public benefits mandated by the statute, be preserved in the face of the restructured ISO market. Similarly, both the state and federal governments have an interest in ensuring the safe operation of nuclear Generating Units, which could be jeopardized if ISO Dispatch required such units to be operated in a manner inconsistent with their technical specifications.

Cities/M-S-R proposes that all Generation "with minimum energy take obligations" come under the definition of Regulatory Must-Take Generation. Initial Brief of Cities/M-S-R at 29. This would include Generation with take-or-pay type fuel contracts or take-or-pay Energy purchase contracts with third-party Generators. *Id.* at 25. However, Cities/M-S-R has provided no regulatory or technical policy reasons for doing this. The take-or-pay contracts it describes are not mandated by federal or state energy policy, dictated by the technical specifications of their Generating Units, or required by any other federal or state policy. Rather, they are simply private contracts entered into in the exercise of the business judgment of the managers of the Generation owners and utilities. These are not the kinds of contracts that were intended to be removed from the competitive marketplace by the relevant provisions of the ISO Tariff.[230] In fact, the presumption is the opposite; absent compelling reasons to the contrary, all

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[230] Note that the Existing Contracts preserved by the ISO Tariff and the Commission's orders relating thereto are *transmission* contracts. Fuel and Energy contracts of the kind described by Cities/M-S-R were never intended to receive this kind of grandfathering treatment. However, it is worth noting that Cities/M-S-R is able to take advantage of the regulatory policy favoring the preservation of existing transmission contracts, since much of its transmission is provided under such grandfathered contracts. *See* ISO Tariff, Section 2.4.4.4.

Generation in the ISO's Control Area is intended to become subject to the free market forces contemplated in the restructuring of the California utility industry.

(3) Allowing New Must-Take Contracts to Come Under the Regulatory Must-Take Definitions Would Interfere With the Establishment of the Restructured Markets.

Cities/M-S-R contends that "there is an improper limitation in the definition of 'Regulatory Must-Take Generation' that the eligible power purchase contracts be 'pre-existing contracts.'" Initial Brief of Cities/M-S-R at 5-6. This is an unacceptable attempt to shelter Generation from market forces indefinitely. Indeed, the Commission contemplates that "the amount of must-take capacity is likely to decline substantially over time, e.g., as QF contracts expire. Thus, we would not expect a QF to retain must-take status beyond the end of its current contract." *Pacific Gas and Electric Co., et al.*, 77 FERC ¶ 61,265, 62,092 (1996). Thus, even QFs, distinguished as they are by compelling state and federal regulatory policies, are not intended to be sheltered forever from market forces. Yet under Cities/M-S-R's proposals, an unlimited amount of Generation would be able to escape market forces forever by the simple expedient of entering into some form of must-take or take-or-pay contract. This would be flatly inconsistent with the Commission's ISO policies and precedents, and with the interest of the California market structure.

For the reasons described above, the ISO respectfully requests that the Commission deny Cities/M-S-R's request that the definitions of Regulatory Must-Take Generation and Eligible Regulatory Must-Take Generation be modified.

O.9. Whether the five percent differential trigger for the establishment of new Congestion Zones is appropriate, and whether Commission approval should be obtained prior to any modification to a Congestion Zone or the establishment of a new Congestion Zone? [Issue No. 662, Docket Nos. EC96-19-000, EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, ER96-1663-000, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005, ER96-1663-006, OA96-28-000. OA96-139-000, OA96-222-000, OA96-76-000, OA97-602-000, and OA97-604-000. Proponent – Cities / M-S-R]

Section 7.2.7 of the ISO Tariff governs the creation, modification, and elimination of Congestion Management Zones. Section 7.2.7.2.1 gives the ISO the authority to create a new Zone if it finds that, within a Zone, the cost to alleviate Congestion on a path over a twelve-month period "is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average Access Charge of the Participating TOs." In order for a new Zone to be an Active Zone, Section 7.2.7.3.1 requires that a "workably competitive Generation market" exist on both sides of the relevant Inter-Zonal Interface to be created for a substantial portion of the year. Currently, there are three active zones: the northern (NP15), central (ZP26) and southern (SP15).

Cities/M-S-R and Palo Alto forthrightly admit that they are concerned that "a real possibility exists that a Congestion Zone could be established in the geographic area in which they are located and that they would suffer additional costs for past investment decisions made by others over which they had no control." Initial Brief of Cities/M-S-R and Palo Alto at 35 (footnote omitted).[231]

[231] Cities/M-S-R and Palo Alto, after noting that the ISO Tariff utilizes both an Access Charge and a Usage Charge, contend that "[t]he interplay of these two concepts results in customers in the Congestion Zone paying amounts in excess of their properly allocated portion of

Rather than focusing on future price signals, they contend that a Congestion Zone should only be created "where the entities which suffer the economic harm resulting from the establishment of the Congestion Zone has some control over the circumstances which caused the Congestion." *Id*. at 38. Cities/M-S-R and Palo Alto criticize the five percent trigger for the creation of new Zones, and criticize the ISO for failing to define the term "workably competitive" as it is used in Section 7.2.7.3.1 of the ISO Tariff. *Id*. at 41-44. They maintain that the establishment of new Congestion Zones is an exercise of ratemaking authority which cannot be delegated to the ISO. *Id*. at 8, 47-49. They also present their own methodology as an alternative to the current approach, by which the ISO would prepare a report setting forth the following: (1) the cause of the Congestion; (2) proposals for remedying the Congestion, together with the proposals' estimated costs; and (3) the entities that would incur the costs. *Id*. at 52-53. The Commission would then determine whether to establish a new Active Congestion Zone. *Id.* at 53.

Nowhere in their initial brief do Cities/M-S-R and Palo Alto mention the Commission's decision regarding Amendment No. 23 and the requirement that the ISO undertake a comprehensive review of its Congestion Management practices. As noted above (e.g., in regard to Issues B.2.a and B.2.e), the Commission has already ordered the ISO to assess "the design of a comprehensive replacement congestion management approach . . . with input from all stakeholder groups, as well as from the Market Surveillance Committee."

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the Participating TO's revenue requirement." Initial Brief of Cities/M-S-R and Palo Alto at 37. This concern is addressed in connection with Issue O.1.a, above.

California Independent System Operator Corporation, 90 FERC at 61,013-14. The proposals of Cities/M-S-R and Palo Alto may well be inapposite, since they presume the outcome of that process. The replacement Congestion Management approach may still be in a form rendering their proposals moot or irrelevant. Thus, an approval or acceptance by the Commission of the proposals by Cities/M-S-R and Palo Alto at this time could short-circuit or frustrate altogether the stakeholder process that the Commission has ordered the ISO to initiate.[232]

With regard to several of the points that Cities/M-S-R and Palo Alto raise, the ISO disagrees that the Commission would be better suited to determine when new Congestion Zones are needed and that "workably competitive" is an impermissibly vague concept. Section 7.2.7.2 of the ISO Tariff provides that the "ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created . . . in accordance with the following procedures." The existing structure, including the establishment of threshold criteria, is the appropriate method to make these determinations. This is borne out by the Commission's approval, in its order on Amendment No. 22, of the ISO's most recently created Congestion Zone. In that order, the Commission explicitly reaffirmed that

> [u]nder the current tariff, the ISO has the authority to create new congestion management zones if the cost to alleviate transmission congestion on a path over a twelve month period is equivalent to at least 5 percent of the product of the rated capacity of the path and

[232] The ISO has already met with the stakeholders to discuss Congestion Management reform and a number of work groups have been formed.

> the weighted average access charge of the participating transmission owners.[233]

The Commission thus agreed that the ISO is the proper entity to determine whether the creation of new Congestion Management Zones is appropriate. It would neither be practical nor an efficient use of the Commission's resources to ask the Commission to launch an investigation every time a new Zone might be created. If the ISO has failed to implement its Zone creation criteria properly, parties are of course free to seek redress by filing a complaint.

In its order on Amendment No. 22, the Commission also rejected the arguments raised by Cities/M-S-R and Palo Alto concerning the ISO's alleged "failure" to define workable competition:

> We reject Metropolitan's argument that we should require the ISO to define "workably competitive." The tariff gives the ISO the discretion to create new zones and to define workable competition. We note that the Annual Report prepared by ISO's Market Surveillance Unit indicated that this definition was under discussion and that the ISO had adopted temporary criteria for the standard, *i.e.*, a minimum of five generation owners in a zone as a criterion for a competitive generation market for congestion management. Moreover, as the Commission noted in a recent order, creation of new zones, even where the market may not be competitive, may help eliminate opportunities to exercise market power.[234]

The ISO continues to believe that the classical economic definition of a workably competitive market is appropriate. That is to say, a workably competitive market is one in which a large number of firms compete to produce the same product and no firm is able to raise prices significantly above system marginal costs for a

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[233] *California Independent System Operator Corporation*, 89 FERC at 61,681.

[234] *Id.* at 61,682 (footnotes omitted).

sustained period of time. Conversely, the ISO believes that a market is not workably competitive if a small number of firms have the ability to raise prices significantly above system marginal costs unimpeded by competition from other suppliers, substitute products, or demand elasticity. The absence of workable competition can be measured in many ways, including calculation of Herfindahl-Hirschmann Indices ("HHIs"), determination that a firm has more than a 20% market share, the number of hours in which a firm can be pivotal, the Residual Supply Index, and – the most conclusive measure – bid mark-up. Again, the outcome of the Congestion Management redesign process may result in a modification of this concept.

As an initial matter, the ISO notes that Cities/M-S-R and Palo Alto are simply trying to revisit claims that were rejected by the Commission in the Commission's approval of Tariff changes relating to the creation of ZP26 (as described in Amendment No. 22). This is not the proper proceeding to raise such claims. Moreover, the arguments of Cities/M-S-R and Palo Alto ignore the crucial role that price signals play in the creation of a new Congestion Management Zone. Prior to the creation of the new Zone, ZP26, Congestion costs over Path 26 were not specifically charged to the Scheduling Coordinators that were using the interface during periods of Congestion. Instead, the resulting *Intra*-Zonal Congestion costs were allocated to all Scheduling Coordinators on a pro rata basis, based on the Demand within the Zone that contains the congested interface. By creating a new Zone and transforming Path 26 into an Inter-Zonal Interface, the ISO is now able to charge Congestion Management costs to the specific Scheduling Coordinators who are using the interface during periods of Congestion and in the direction of Congestion.

The projected Inter-Zonal Congestion costs that Cities/M-S-R and Palo Alto cite based on an ISO report[235] reflect only what the Inter-Zonal Congestion costs would have been during the period studied if Market Participants had not modified their behavior in response to the price signals sent via the Inter-Zonal Congestion Management system, i.e., if they had scheduled the same transactions as they had scheduled before Path 26 became an Inter-Zonal Interface. The ISO report goes on to explain, however, that the behavior of Scheduling Coordinators is expected to change once the appropriate price signals are being sent. Figure 2-5 of the Report demonstrates that only a few Scheduling Coordinators would be charged for the great majority of projected Inter-Zonal Congestion costs over Path 26. As the ISO report explains, these Scheduling Coordinators "would be able to self-manage congestion and alter their bidding behavior to reduce their exposure to congestion costs."[236] Thus, the ISO anticipates that the report's projections are not an accurate reflection of any increases in Congestion costs resulting from the creation of the new Zone. Scheduling Coordinators with better price signals will be able to schedule more efficiently. More importantly, the costs of managing Congestion on Path 26 will now be allocated to those entities that are creating the Congestion by scheduling

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[235] *See* Initial Brief of Cities/M-S-R and Palo Alto at 50-51. The ISO report which Cities/M-S-R and Palo Alto cite is the *Report to the Federal Energy Regulatory Commission: Studies Conducted Pursuant to the October 30, 1997 Order*, Docket No. ER00-703-000 (filed Dec. 1, 1999) ("December 1999 Report").

[236] December 1999 Report at 30.

over Path 26 during periods of Congestion. This result is wholly consistent with the Commission's emphasis on sending the proper price signals through Congestion Management mechanisms. *See California Independent System Operator Corporation*, 90 FERC at 61,013.

Accordingly, the ISO respectfully requests that the Commission deny the request of Cities/M-S-R and Palo Alto that the ISO be directed to modify its approach to Zone creation, thus allowing the stakeholder process ordered by the Commission to move forward effectively. Cities/M-S-R and Palo Alto are, or course, free to participate in the stakeholder process, and may further pursue their position when the outcome of that process is presented to the Commission.

O.10. <u>Does the ISO Tariff contain an inappropriate inconsistency between the computation of the Wheeling Access Charge and the disbursement of Wheeling Revenues (sections 2.4.4.3.1 vs. 7.1.4.3)? [Issue No. 645, Docket Nos. EC96-19-009 and ER96-1663-010. Proponents - TANC and DWR]</u>

Under the ISO Tariff, "Wheeling" refers to the transmission of Energy on the ISO Controlled Grid to serve a Load located outside the ISO Controlled Grid. The current approach is for a Scheduling Coordinator that wheels Energy must pay a Wheeling Access Charge, which is based on the TRR of the Participating TO whose facilities comprise the Scheduling Point at which the Energy exits the ISO Controlled Grid. Where more than one Participating TO owns or has a contractual entitlement to those facilities, the Wheeling Access Charge is weighted based on the relative shares of the Participating TOs to transmission capacity at the Scheduling Point. *See* ISO Tariff, Section 7.1.4.2.[237] Wheeling

[237] For example, if the transmission capacity of a Scheduling Point is 300 MW and Participating TO "A" owns facilities at the Scheduling Point with a capacity of 200 MW and

Access Charge revenues received by the ISO are disbursed to Participating TOs in proportion to their respective TRRs. *Id.*, Section 7.1.4.3.[238] The revenues received are required to be credited against each Participating TO's TRBA and to be reflected in the Access Charge, payable by customers withdrawing Energy from the ISO Controlled Grid. *Id.*, Section 7.1.

TANC notes that the use of different methodologies for developing the Wheeling Access Charge at a jointly owned Scheduling Point and for distributing Wheeling Access Charge revenues to Participating TOs could create situations in which a Participating TO receives a share of revenues that is disproportionate to its ownership of (or Entitlement to) the transmission capacity at the Scheduling Point. Initial Brief of TANC at 19-20. TANC argues that the same methodology should be used for both purposes. *Id.*

The ISO disagrees that the same methodology must be used for developing Wheeling Access Charges for jointly owned Scheduling Points and for disbursing Wheeling Access Charge revenues to Participating TOs. Rather, an appropriate methodology should be used for each purpose.[239] The current ISO Tariff does this. When a Wheeling customer uses the transmission capacity

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Participating TO "B" owns facilities with a capacity of 100 MW, then the Wheeling Access Charge is a blend of Participating TO A's Transmission Revenue Requirement and Participating TO B's Transmission Revenue Requirement in a 2:1 ratio.

[238] Where the Participating TO's capacity at a Scheduling Point is represented by a contractual entitlement to transmission service that has been converted to ISO transmission service, the Participating TO receives a share of Wheeling Access Charge revenues with respect to that capacity reflecting its payments under the contract as its TRR. ISO Tariff, Section 2.4.4.3.1.4.

[239] *See Central Hudson Gas & Electric Corp., et al.,* 88 FERC ¶ 61,138, at 61,384-85 (1999) (approving marginal charge for transmission losses, with excess revenues credited against scheduling charge paid by loads).

at a jointly owned Scheduling Point to transmit Energy off the ISO Controlled Grid, it is not using the transmission capacity of any particular Participating TO. Rather, it is using the capacity owned (or contractually controlled) by all of the Participating TOs whose facilities constitute that Scheduling Point. It is reasonable to base the Wheeling Access Charge on the proportionate shares of the capacity at the Scheduling Point owned or contractually controlled by each Participating TO. TANC does not contend otherwise.

When the ISO disburses Wheeling Access Charge revenues for each month to the Participating TOs, it does *not* attempt to match usage of capacity and revenues on a Scheduling-Point-by-Scheduling-Point basis. Rather, recognizing that all Participating TOs' facilities are used for different Wheeling transactions during a month, including facilities that are remote from particular Scheduling Points, the revenues are distributed in proportion to the Participating TOs' TRRs. This enables each Participating TO to credit against the Access Charge paid by customers on the ISO Controlled Grid a portion of the Wheeling Access Charge revenues that is proportionate to the TRRs upon which that Access Charge is based. Again, TANC does not challenge the reasonableness of this approach.

TANC is correct that the combination of these approaches could lead to mismatches if transmission capacity usage and Wheeling revenues are compared on a Scheduling-Point-by-Scheduling-Point basis. Avoiding such mismatches, however, is neither necessary nor appropriate.[240] Rather, the objective in this case is to charge Wheeling customers a reasonable rate for the use of the ISO Controlled Grid and to credit an appropriate amount to the customers paying the Access Charge of each Participating TO. As explained above, the ISO Tariff achieves this objective. TANC's demand for a modification to the Wheeling Access Charge rate methodology or to the distribution of Wheeling revenues among Participating TOs should accordingly be denied.

Moreover, in its March 31, 2000 filing of a revised Access Charge methodology, the ISO proposed to modify both the assessment of Wheeling charges and the disbursement of Wheeling revenues. To the extent that TANC remains dissatisfied with the revised methodology, it may raise the issue in the Amendment No. 27 docket.

O.11. <u>Whether section 2.4.4.5.1.6 of the ISO Tariff, which allows the ISO to make available any unused transmission capacity which has not been scheduled by the Existing Rights holder by the start of the ISO's Hour-Ahead scheduling process, inappropriately allows for appropriation of transmission capacity without payment of compensation, is inconsistent with preservation of within-the-hour scheduling flexibility, and could impair the interests of non-Participating Transmission Owners or Entitlements of Existing Contracts rights holders that were financed with tax-exempt bonds? [Issue No. 643, Docket Nos. EC96-19-009 and ER96-1663-010. Proponents - TANC, Cities / M-S-R, and Palo Alto]</u>

Many Existing Contracts afford transmission customers the opportunity to schedule their use of a Participating TO's facilities after the close of the ISO's scheduling deadline for its Hour-Ahead scheduling process (two hours prior to the operating hour). Section 2.4.4.5.1.6 of the ISO Tariff requires the ISO to coordinate the scheduling of those transmission customers' use of their Existing Rights with the scheduling of ISO Transmission Service and authorizes the ISO to make unscheduled capacity associated with Existing Rights available to other

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[240] *See id.* at 61,385.

Market Participants desiring to use the capacity. There is no requirement that a holder of Existing Rights be compensated when the unscheduled transmission capacity is used by another Market Participant.

In the October 1997 Order, the Commission approved this aspect of the ISO Tariff, stating as follows:

> We disagree with [intervenors] who argue that the ISO should compensate those entities with existing capacity Entitlements for the use of that capacity in the hour-ahead market. Traditionally, if a customer did not use all of its transmission entitlement, the transmission provider and other third-party customers could utilize that capacity on a non-firm basis.

October 1997 Order, 81 FERC at 61,471 (footnote omitted).

Proponents challenge this ruling. Joint Initial Brief on Issues O.2.a, O.2.c, and O.11, at 8-10. They do not, however, challenge its application to transmission rights arising under Existing Contracts a customer may have with a Participating TO, i.e., pre-existing contractual rights to use transmission capacity on the ISO Controlled Grid. They argue only that the ISO should not be entitled to make available under the ISO Tariff, without compensation, transmission capacity on facilities owned by an entity that is not a Participating TO. *Id.*

This objection is based on a misreading of Section 2.4.4.5.1.6 of the ISO Tariff, which applies only to contractual reservations of capacity on transmission facilities and Entitlements of Participating TOs. By its terms, Section 2.4.4.5.1.6 is limited to "those Existing Rights and Non-Converted Rights the use of which has not been scheduled by the rights-holders by the start of the ISO's Hour-Ahead scheduling process." "Existing Rights" are defined in the ISO Tariff as "transmission service rights of non-Participating TOs" that arise under

"Existing Contracts." ISO Tariff, Section 2.4.4.1.1 and Appendix A. "Existing Contracts" are in turn defined as "contracts which grant transmission service rights in existence on the ISO Operations date."[241] Existing Contracts are recognized as "Encumbrances," i.e., "legal restriction[s] or covenant[s] binding on a Participating Transmission Owner" that the ISO must take into consideration in operating the facilities and Entitlements that a Participating TO has turned over to the ISO's Operational Control. ISO Tariff, Appendix A, definition of "Existing Contracts." The discussion in Section 2.4.4.5.1.6 of the ISO's authority to make available to other Market Participants unused transmission capacity associated with Existing Rights thus relates only to idle transmission capacity on the ISO Controlled Grid that had been reserved under an Existing Contract. Objections that the ISO should not be permitted to make available to other Market Participants capacity on transmission facilities or entitlements that have not been turned over to its Operational Control are misplaced, because Section 2.4.4.5.1.6 does not authorize the ISO to do so.

As Proponents indicate, there are transmission facilities within the Control Area operated by the ISO that are owned by entities that have not yet chosen to become Participating TOs. To facilitate the coordinated operation of these facilities with the balance of the California transmission system, the owner or owners of the facilities entered into contracts with one or more of the investor-owned utilities that operated control areas in California prior to the start-

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[241] ISO Tariff, Appendix A. Section 2.4.4.5.1.6 also refers to "Non-Converted Rights," which are Existing Rights that an entity may elect, during an interim period, not to convert to ISO transmission service when it becomes a Participating TO. *See* ISO Tariff, Section 2.4.4.2.1.

up of the ISO. These contracts, which typically grant reciprocal usage rights under defined circumstances, also constitute Existing Contracts. Ever since the ISO began operating the ISO's Control Area, the former control area operators have provided operating instructions to the ISO with respect to these contracts, under which the ISO has carried out scheduling and other responsibilities as part of its operation of the ISO Control Area. *See* ISO Tariff, Sections 2.4.4.5.1.1 – 2.4.4.5.1.3. That is the case with respect to the California-Oregon Transmission Project, to which Proponents refer. The ISO's implementation of those operating instructions is not, as Proponents imply, an improper attempt by the ISO to expand its operations to encompass transmission facilities that have not been turned over to its Operational Control. Rather, it is a necessary part of the ISO's operation of the Control Area within which the facilities are located and its implementation of Existing Contracts in accordance with the ISO Tariff.

O.12. <u>With respect to ISO Tariff Amendment No. 7, can the ISO's "temporary rule" to impose a price cap for Imbalance Energy bids evaluated by the ISO's BEEP software be used to bar generators from bidding above the price cap to supply Imbalance Energy? [Issue No. 634, Docket Nos. EC96-19-030 and ER96-1663-031. Proponent - HIPG]</u>

The ISO understands that no initial brief was filed with respect to this issue.

O.13. <u>Whether the priority for Reliability Must-Run Generation in Amendment No. 7 is improper? [Issue Nos. 253, 641, 642, and 670, Docket Nos. EC96-19-023, EC96-19-030, ER96-1663-024, and ER96-1663-031. Proponents - PX, DWR, Turlock, Cities / M-S-R, and CAC]</u>

Cities/M-S-R, Turlock, DWR, EPUC, and CAC raise concerns about the Commission's acceptance of the ISO's proposal to establish for Reliability

Must-Run Generation a priority to use congested transmission facilities. *See* Joint Initial Brief on Issue O.13, at 3-4. These Proponents contend that the Commission erred in establishing a higher priority for Reliability Must-Run Generation than that previously established under Existing Contracts. *Id.* Additionally, Proponents assert that the Commission's order on Amendment No. 7 inappropriately diminishes the rights of parties under their Existing Contracts. *Id.*

Contrary to Proponents' assertion, the Commission did not "back handedly" (*id.* at 5) accept this aspect of Amendment No. 7. The requests for rehearing on this issue fail to recognize that the fundamental purpose of the Dispatch of Reliability Must-Run Generation is to maintain the reliability of the ISO Controlled Grid, facilitating the deliveries called for by the Existing Contracts. If the output of Reliability Must-Run Generation could not be delivered, it could not serve its intended purpose: the maintenance of reliability for *all* those that rely on the ISO Controlled Grid. Accordingly, Reliability Must-Run Generation must have a higher priority of use than all other uses of congested transmission paths. Absent this priority, the ISO would not be able to ensure the reliable delivery of Energy under Existing Contracts.

Reliability Must-Run Generation, by definition, is Generation that the ISO determines is required to be on-line to meet reliability requirements, including Generation needed to meet Load and to provide Voltage Support and system security. If the ISO assigned a higher priority to Existing Contracts rather than to Reliability Must-Run Generation, the very service provided under those Existing Contracts might be jeopardized.

The assertion that the ISO's proposal "will result in the partial abrogation of rights" under Existing Contracts (*id.* at 3) is unfounded. Proponents recognize that Reliability Must-Run Generation provides local reliability support "particularly for locations where limited transmission capacity makes reliance on generation from distant resources infeasible." *Id.* at 19. Yet they fail to recognize the implications of this restriction. If Reliability Must-Run Generation is local in nature, providing a priority over the limited portions of the ISO Controlled Grid needed to ensure availability will not adversely affect service elsewhere under Existing Contracts. Tellingly, Proponents fail to cite a single example of a situation in which their transmission service has actually been interrupted. The ISO believes that Reliability Must-Run priorities have not resulted in changes to Existing Contract schedules in either the Day-Ahead or Hour-Ahead Markets.

Proponents provide a limited recitation of their rights under Existing Contracts. *Id.* at 6-12. They claim that "these firm transmission rights, under the terms of the Existing Contracts, are not curtailable in order to provide continued transmission service for RMR generation." *Id.* at 11. However, Proponents fail to recite the provisions of these Existing Contracts that give the transmission provider the right to curtail service under appropriate circumstances.

For example, the City of Santa Clara receives point-to-point transmission service under PG&E Rate Schedule No. 85. *Id.* at 7 n.10. Proponents state that "the firm transmission service provided thereunder is not subject to curtailment in favor of Reliability Must-Run Generation under the terms of the Santa Clara IA." *Id.* at 7. Yet, Proponents fail to note that pursuant to Section 6.4.1 of that agreement:

> PGandE shall not be required by this Agreement to provide Firm Transmission service or Interruptible Transmission Service if the proposed transaction would be inconsistent with Good Utility Practice or if the necessary transmission facilities are committed at the time of the request to be fully loaded during the period for which service is requested or having been previously reserved by PGandE for emergency purposes, loop flow, or other uses consistent with Good Utility Practice.

The ISO calls on Reliability Must-Run Generation, in accordance with Good Utility Practice, when necessary to meet Applicable Reliability Criteria to promote the stability of the ISO Controlled Grid. Proponents are being unduly restrictive when they complain that this Interconnection Agreement executed in 1983, over a decade prior to the formation of the ISO, does not include any reference to Reliability Must-Run Generation. Joint Initial Brief on Issue O.13, at 7. While this and the other cited agreements could not of course reflect the market restructuring that would take place more than a decade later, they did properly recognize that the particular service provided was secondary to the overall management of the system for reliability.

Furthermore, Proponents' assertion that the ISO's Amendment No. 7 proposal violated the Commission's prior order rejecting Amendment No. 3 (*id.* at 15-17) is without merit. The ISO proposed in Amendment No. 3 to establish a priority of use for Regulatory Must-Take and Regulatory Must-Run resources, as well as Reliability Must-Run Generation. Proponents contend that there is no difference between Regulatory Must-Run and Regulatory Must-Take resources on the one hand, and Reliability Must-Run Generation on the other. *See id.* at 15. In fact, the two are very different. Regulatory Must-Take and Regulatory Must-Run resources are so designated because those resources were developed under arrangements that implemented mandates of the CPUC. They were created out of a need to preserve certain existing contractual, legal, and regulatory obligations. Units were identified as Reliability Must-Run for reliability to preserve the integrity of the electric system in the transition from an integrated utility regime to that of an unbundled system (i.e., transmission and Generation integrated by a utility versus the ISO only having control over transmission and the market being responsible for providing Generation).

Proponents' contention that the "ISO apparently concurs that . . . Amendment No. 7 [is] cut from the same cloth as Amendment No. 3" (*id.* at 16) is without foundation. The ISO clearly distinguished the changes proposed in Amendment No.7 (i.e., to establish a priority solely for Reliability Must-Run Generation), with those changes proposed in Amendment No. 3 (i.e., to establish a priority for Regulatory Must-Take and Regulatory Must-Run Resources *and* Reliability Must-Run resources). *See* Transmittal Letter for Amendment No. 7 filing, Docket Nos. EC96-19-023 and ER96-1663-024 (Mar. 31, 1998), at 4-5. While the Commission rejected the ISO's proposed Amendment No. 3, it did not specifically address the ISO's proposal to establish a priority for Reliability Must-Run Generation. Moreover, Proponents' clarification that even if the Commission were correct in establishing a priority for Reliability Must-Run Generation, such a preference should not be established for all Reliability Must-Run Generation (Joint Initial Brief on Issue O.13, at 17) is unnecessary. Clearly, the ISO did not intend to establish a priority for Generation sold from a Reliability Must-Run unit when that unit was selling Generation in the market. The ISO intends only to give the Reliability Must-Run Generation priority status when the Reliability Must-Run unit that produces it is called upon to operate by the ISO.

The Commission should deny the rehearing requests on this issue. The determination to accord Reliability Must-Run Generation a priority is an appropriate means of ensuring the reliability of the ISO Controlled Grid, which will facilitate rather than curtail service under Existing Contracts.

O.14. <u>Did the Commission's October 30, 1997 decision to strike certain overgeneration provisions of the ISO Tariff result in consequences of overgeneration to be borne only by some, and not all of the responsible parties, and did it produce an inequitable and discriminatory result. [Issue No. 366, Docket Nos. EC96-19-009 and ER96-1663-010. Proponents - PG&E, SDG&E, and SoCal Edison]</u>

In the October 1997 Order, the Commission required the removal from the ISO Tariff of provisions that would, in certain circumstances, allocate responsibility for Generation reductions required to manage Overgeneration among the PX and other Scheduling Coordinators serving End-Users in the Service Areas of the Participating TOs. October 1997 Order, 81 FERC at 61,525. The Commission determined that each Scheduling Coordinator is appropriately held responsible for submitting Balanced Schedules in the Day-Ahead and Hour-Ahead markets and therefore must manage any Overgeneration within its own portfolio. *Id.* at 61,526. The ISO accordingly eliminated the Day-Ahead and Hour-Ahead scheduling provisions from the ISO Tariff, retaining only provisions relating to the management of Overgeneration that occurs in real-time operations (i.e., after the close of the Hour-Ahead markets), notwithstanding Scheduling Coordinators' submission of Balanced Schedules in the Day-Ahead and Hour-Ahead markets. To the extent that Overgeneration exists, those provisions require the ISO to rely first on decremental bids submitted by Scheduling Coordinators. The introduction of the capability to handle negatively priced bids for Imbalance Energy as part of Amendment No. 13 (*see California Independent System Operator Corporation*, 86 FERC at 61,420-21) has enhanced the ISO's ability to deal with real-time

Overgeneration through economic bids.

PG&E and SCE urge the Commission to reconsider its ruling regarding the forward management of Overgeneration. They argue that, inasmuch as commitments were made to Regulatory Must-Take Generation and Regulatory Must-Run Generation to meet the needs of all the End-Use Customers that the Participating TOs served before the introduction of direct retail access, Scheduling Coordinators now serving those same customers should contribute to the solution of Overgeneration conditions created by that generation. Joint Initial Brief of PG&E and SCE on Issue O.14, at 8-10.

This issue does not concern questions of reliability or operability, but of the fair allocation of the costs of Overgeneration associated with Regulatory Must-Take Generation and Regulatory Must-Run Generation. The ISO notes that special rules and accommodations are not required to replace what has proven to be a problem the market is able to solve efficiently through bids submitted by Scheduling Coordinators. Prior to proving the market's capability to resolve Overgeneration, and indeed prior to ISO start-up, the Commission rejected the ISO's involvement in managing Overgeneration among Scheduling Coordinators. Proponents have questioned the fairness of the Commission's October 1997 Order but have not suggested (much less shown) any material harm arising in the absence of special rules applied by the ISO in the Day-Ahead and Hour-Ahead Energy markets. Indeed, Proponents present no new evidence indicating that the Commission's ruling has had unfair results. Therefore, the ISO does not believe there is any compelling reasons for the Commission to reconsider its ruling at this time.

III. CONCLUSION

Wherefore, for the reasons discussed above, the ISO respectfully requests that the Commission adopt the positions contained in this Answering Brief.

Respectfully submitted,

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Dated: April 10, 2000

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents by first class mail, postage prepaid, upon each person designated on the restricted service list adopted by the Federal Energy Regulatory Commission in this Proceeding.

Dated at Washington, D.C. on this 10th day of April, 2000.

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