UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 478

California Independent System Operator Corporation	Docket Nos.	ER00-2019-006 ER00-2019-012 ER00-2019-013
California Independent System Operator Corporation	Docket Nos.	ER01-819-002 ER01-819-006
California Independent System Operator Corporation	Docket Nos.	ER03-608-000 ER03-608-004

OPINION AFFIRMING IN PART AND REVERSING IN PART INITIAL DECISION, AFFIRMING PARTIAL INITIAL DECISION, DENYING REHEARING AND DISMISSING COMPLIANCE FILING

Issued: December 21, 2004

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

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OPINION AFFIRMING IN PART AND REVERSING IN PART INITIAL DECISION, AFFIRMING PARTIAL INITIAL DECISION, DENYING REHEARING AND DISMISSING COMPLIANCE FILING

(Issued December 21, 2004)

1. This case arises from filings by the California Independent System Operator Corporation (ISO) concerning its Transmission Access Charge (TAC), pursuant to which the embedded costs of the ISO-controlled grid are recovered. In this order, we review an Initial Decision issued on these filings,[1] a Partial Initial Decision previously issued by the presiding judge in these proceedings, resolving certain issues,[2] as well as a compliance filing and requests for rehearing arising from the Commission orders establishing the procedures in these proceedings and setting out guidelines on particular issues.[3] As

[1] *Calif. Indep. Sys. Operator Corp.*, 106 FERC ¶ 63,026 (2004) (Initial Decision).

[2] *Calif. Indep. Sys. Operator Corp*., 105 FERC ¶ 63,008 (2003) (Partial Initial Decision).

[3] *Calif. Indep. Sys. Operator Corp.*, 91 FERC ¶ 61,205 (2000) (May 2000 Order), *on reh'g*, 104 FERC ¶ 61,062 (2003) (July 2003 Order).

discussed below, the Commission today affirms the Initial Decision in most respects, reverses the Initial Decision on the issue of cost shift caps, affirms the Partial Initial Decision, denies the requests for rehearing, defers decision on the issue of whether there should be a behind the meter exception to assessment of the TAC on a gross load basis, and dismisses the ISO's compliance filing as premature.

2. This order benefits customers by ensuring that the ISO's transmission costs are recovered on a just and reasonable basis.

Background

3. While the history of this case is well-covered by the prior orders (especially the Initial Decision), we describe the major developments in order to put our decisions today into the proper context. On March 31, 2000, the ISO filed Amendment No. 27 to its tariff, proposing the TAC, which the Commission accepted and suspended in the May 2000 Order. Until the ISO's filing, the access charge consisted of three separate zone rates based on the revenue requirements of the Participating Transmission Owners (TO).[4] With Amendment No. 27, the ISO proposed a ten-year transition period during which High Voltage Access Charges for the TAC areas[5] would merge to form a single grid-wide access charge. This would be accomplished by blending a cumulative ten percent per year of the individual High Voltage Transmission Revenue Requirements (TRR) for each TAC area with the sum of the TRRs of the Participating TOs.

4. In the May 2000 Order, the Commission accepted the proposed tariff amendment with effective date of June 1, 2000, subject to refund, suspended it for a nominal period, and established settlement judge procedures. Additionally, the May 2000 Order, in order to assist settlement efforts, discussed the major issues that would have to be set for hearing. Among these issues were whether the ten-year transition period and proposed limits on cost shifts, as well as the proposed treatment of Firm Transmission Rights (FTRs) were just and reasonable, and whether the ISO's exception from gross load billing for existing Qualifying Facilities was non-discriminatory.

5. Settlement negotiations continued for the next two and a half years, but proved to be unsuccessful. In December 2002, the Commission's Chief Administrative Law Judge therefore terminated the settlement judge procedures and initiated hearing procedures.

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[4] The three original Participating TOs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SoCal Edison), and San Diego Gas & Electric (SDG&E).

[5] The TAC areas correspond to the historical control areas of the three original Participating TOs.

6. A number of parties requested rehearing of the May 2000 Order. In the July 2003 Order, the Commission generally denied these requests for rehearing. The July 2003 Order also spawned a number of requests for rehearing and/or clarification, which we resolve in section III below.

7. On March 11, 2003, the ISO filed Amendment 49 to its tariff, proposing certain modifications and clarifications to Amendment 27 and the TAC rate design. In an order issued on May 30, 2003,[6] the Commission accepted in part and rejected in part the ISO's proposed tariff amendment, and consolidated the hearing on the amendment with the ongoing Amendment 27 proceeding. Several parties requested rehearing of that order as well, which we address in section IV below.

8. Meanwhile, the hearing procedures continued under the auspices of the presiding judge. In the course of the proceeding, SoCal Edison filed a motion for partial summary disposition on the issue of what facilities should be placed under the ISO's operational control and thus included in the TRRs of the Participating TOs. On October 21, 2003, the judge issued the Partial Initial Decision on review here.

9. Subsequently, the presiding judge conducted the hearing in these proceedings, from October 21, 2003, until November 14, 2003. The active parties included the ISO; SoCal Edison; Cogeneration Association of America and Energy Producers and Users Coalition (CAC/EPUC); PG&E; SDG&E; State Water Contractors and Metropolitan Water District of Southern California (SWC/Metropolitan); Modesto Irrigation District (Modesto); Transmission Agency of Northern California (TANC); Northern California Power Agency (NCPA); the California Department of Water Resources State Water Project (DWR),[7] Electricity Oversight Board (EOB); City of Vernon, California (Vernon); Cities of Anaheim, Azusa, Banning, Coulton, and Riverside, California (Cities); and Commission trial staff (Trial Staff).

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[6] *Calif. Indep. Sys. Operator Corp.*, 103 FERC ¶ 61,260 (2003) (May 2003 Order).

[7] DWR has sometimes been referred to in this proceeding as SWP.

Discussion

I. The Initial Decision

A. Issues Summarily Affirmed

10. Of the issues resolved by the Initial Decision and raised on exceptions, we address the following: (1) phantom congestion; (2) FTRs; (3) high-low voltage split; and (4) cost shift caps.

11. Having reviewed the record, the Initial Decision, and the briefs of the parties, the Commission finds that the remaining issues raised on exceptions were properly resolved by the presiding judge. We therefore deny the exceptions and summarily affirm and adopt the findings by the presiding judge with respect to (1) the relevant factors informing the decision, (2) time-of-use rates, (3) treatment of existing contracts, and (4) evidentiary determinations. The Commission also affirms all other findings and conclusions of the presiding judge.

B. Phantom Congestion

1. Initial Decision

12. The Initial Decision recognized that in the May 2000 Order, the Commission had accepted the ISO's view that phantom congestion is caused by "a disparity between the ISO's scheduling timelines in the day-ahead and hour-ahead markets and the scheduling timelines accorded existing rights holders in their existing contracts."[8] In other words, "[b]ecause the Existing Rights contracts allow scheduling changes after the ISO scheduling deadlines, available transmission capacity remains unutilized."[9] It was therefore "axiomatic," the presiding judge determined, "that phantom congestion exists."[10] She went on to observe that nearly every party agreed with this conclusion, though disagreement existed on how to label the concept.

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[8] Initial Decision, 106 FERC ¶ 63,026, at P 80 (citation omitted).

[9] *Id.* (quoting May 2000 Order, 91 FERC at 61,727). The judge rejected Trial Staff's and TANC's arguments that the ISO and the Existing Transmission Contract facilitators, such as PG&E, should be held responsible for phantom congestion. The judge pointed out that, not only are they acting in a Commission-approved manner to administer the existing contracts, but also that they mitigate such congestion when possible.

[10] *Id.* at P 70 (citing May 2000 Order, 91 FERC at 61,727).

13. The Initial Decision further acknowledged that the Commission had identified phantom congestion as a "market inefficiency that must be addressed and rectified as quickly as possible."[11] At the same time, the presiding judge explained, the Commission has rejected arguments that the ISO should resolve the issue through modifying its software or that the ISO should continue to allow phantom congestion to exist "because the existing contract holders valued the scheduling flexibility accorded them by virtue of their contracts."[12] Furthermore, the judge noted that the Commission had recognized that the ISO has sound rationale for the difference between its own and the Existing Transmission Contract holders' scheduling timelines, which caused phantom congestion.[13]

14. Based on the record presented, the Initial Decision concluded that "phantom congestion's economic impact is difficult to quantify."[14] Therefore, the judge concluded, the TAC proceeding "is not the appropriate vehicle to remedy the phantom congestion problem."[15] In this regard, the judge was influenced by the possibility of alternative means to address the issue of phantom congestion, particularly the ISO's MD02 proposal to redesign the California ISO market.[16] The judge also referred to the anticipated expiration of existing contracts as a solution to the problem of phantom congestion.

2. Exceptions

15. Modesto and TANC filed exceptions with regard to the issue of phantom congestion. Modesto first asserts that the Initial Decision erred in ruling that phantom congestion exists. Rather, Modesto contends that the very real transmission availability problem, incorrectly styled by the ISO as phantom congestion, is of the ISO's own making. Modesto claims that the ISO deliberately structured its Tariff and Protocols and directed the development of Operating Procedures and software to withhold the disputed Existing Transmission Contract capacity from use by others.[17] According to Modesto, the Initial Decision erroneously concluded that the Commission had already decided the matter, and thereby neglected to reach Modesto's arguments against the existence of phantom congestion.

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[11] *Id.*

[12] *Id.* at P 81.

[13] *Id.* at P 82.

[14] *Id.* at P 103.

[15] *Id.* at P 119.

[16] *Calif. Indep. Sys. Operator Corp.*, Docket Nos. ER02-1656 and EL01-68.

[17] TANC Brief on Exceptions at 20.

16. TANC contends that the Initial Decision's finding that phantom congestion exists ignored TANC's arguments to the contrary. Moreover, in TANC's view, the phenomenon to which the ISO refers as phantom congestion is a product of the ISO's own making. In this context, TANC adopts Trial Staff's contention that "PG&E and the ISO may be reserving more capacity until real time in the name of [Existing Transmission Contract] rights holders than those rights holders want or intend to use."[18]

3. Commission Determination

17. The Commission denies Modesto's and TANC's exceptions on the phantom congestion issue. As described above, we have previously endorsed the ISO's assessment that phantom congestion is a condition occurring because the transmission capacity of Existing Transmission Contracts remains unscheduled by the contract holder, while the ISO cannot make use of the unscheduled capacity in the day-ahead and hour-ahead markets.[19] Indeed, even Modesto and TANC acknowledge that there are periods when this scheduling problem occurs.[20] Thus, we affirm the judge's finding that phantom congestion does exist.

18. The Commission also denies the exceptions of Modesto and TANC and affirms the presiding judge with respect to the cause of phantom congestion. The presiding judge correctly found that phantom congestion is caused by a disparity between the ISO's scheduling timelines in the day-ahead and hour-ahead markets and the scheduling timelines of existing rights holders.[21]

19. We reject the theory of Modesto and TANC that the ISO is the cause of phantom congestion. Rather, it is clear that the ISO is faced with the problem of trying to administer a large number of Existing Transmission Contracts, many of which have non-standard and non-uniform terms and conditions creating the disparity in schedules. Furthermore, the ISO has a responsibility to create procedures to accommodate the various Existing Transmission Contract terms and conditions. While our preference for the ISO to develop rules and procedures that are broad enough to encompass overall participation, while taking into account the special provisions of Existing Transmission

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[18] *Id.* at 26-27.

[19] May 2000 Order, 91 FERC at 61,727. *See* Ex. ISO-1 at 39:1-17.

[20] *See* Ex. MOD-1 at 7-9.

[21] For example, we note that, while market participants are required to schedule transmission in the day-ahead and hour-ahead markets, some Existing Transmission Contract rights holders have authority to schedule up to twenty minutes prior to the start of the operating hour, and in some cases even during the operating hour.

Contracts, we cannot hold the ISO responsible for problems resulting from the misalignment of the ISO's protocols with the terms and conditions of the previously-existing contracts.

20. The Commission also agrees with the presiding judge the TAC proceeding is not the appropriate vehicle to remedy the phantom congestion problem. First, as the Initial Decision concluded, the economic impact of phantom congestion is not clear from the record presented. Second, as the judge points out, this problem is not permanent, and will die a natural death with the expiration of the Existing Transmission Contracts. Third, and more importantly, there are other proceedings in which the problem of phantom congestion is more appropriately addressed.

21. In this regard, the Commission notes that on July 22, 2003, the ISO submitted in its Market Redesign Technology Upgrade proposal (MRTU) (formerly known as MD02) an alternative to deal with Existing Transmission Contracts, phantom congestion, and the avoidance or reduction of costs and inefficiencies associated with the ISO's administration of Existing Transmission Contracts. We issued an order in response, indicating that while we were encouraged by the ISO's progress on the issue, a definitive ruling would have to await further developments.[22] On March 5, 2004, the ISO published a white paper proposal to address the issues raised by the Commission in the October 2003 Order. On September 20, 2004, the ISO published a revision to the white paper, anticipating that action which would resolve the issue of phantom congestion by appropriately allocating congestion charges associated with existing contracts should be ready for filing with the Commission by the end of 2004. On December 8, 2004, the ISO filed a proposal for honoring Existing Transmission Contracts in the MRTU proceeding in Docket No. ER02-1656-021.

C. <u>Firm Transmission Rights</u>

1. <u>Initial Decision</u>

22. Under the ISO's proposed section 9.4.3 of the ISO Tariff, during the ten-year transition period (or alternatively, under a shorter period representing the term of an Existing Transmission Contract), a new Participating TO that converts its Existing Rights to ISO transmission service will directly receive FTRs commensurate with those rights, without having to participate in the ISO's FTR auction. The quantity of the FTRs that a new Participating TO will receive for its transmission capacity will be determined when a Transmission Control Agreement is executed by the ISO and the new Participating TO.

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[22] *Calif. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140, at P 202 (2003) (October 2003 Order).

23. In reviewing specific issues raised by the parties concerning FTRs, the presiding judge's touchstone was that the Commission had found that the ISO's proposed treatment of FTRs was reasonable.[23] The judge observed that the Commission had accepted the ISO's explanation of section 9.4.3:

> [T]he proposal to exempt new Participating TOs from the auction process during the transition period is a feature that has been offered as an inducement to encourage participation in the ISO. The proposal will afford new Participating TOs protection against cost increases during the transition period.[[24]]

The judge further acknowledged that the Commission had also "explicitly rejected arguments that the ISO's FTR proposal is unduly discriminatory."[25] Thus, she concluded that, consistent with the Commission's rulings, the treatment of FTRs for new Participating TOs in section 9.4.3 of the ISO Tariff is just, reasonable, and not unduly discriminatory.

24. Having established the foundation of the issue, the presiding judge turned to the specific arguments raised by the parties concerning FTRs during the hearing. First, she considered whether the provisions of the ISO Tariff relating to the netting of usage charges against usage charge revenue associated with FTRs received under section 9.4.3 (specifically, the definitions of New Firm Transmission Rights Revenue and Transmission Revenue Credit) were just, reasonable, and not unduly discriminatory. The presiding judge rejected proposals that would have conferred a financial advantage beyond the proportionate benefit conveyed by section 9.4.3. She found that challenges to the proposed change as an unreasonable limitation on the ability of new Participating TOs to credit ISO transmission charges against FTR revenues were simply not consistent with the limited purpose of section 9.4.3.

25. The judge next evaluated claims by certain parties challenging the provision that FTRs to new Participating TOs under section 9.4.3 terminate at the earlier of the end of the transition period or termination of an existing contract. The Initial Decision rejected these contentions, concluding that the termination provisions were both reasonable and consistent with Commission precedent.[26]

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[23] Initial Decision, 106 FERC ¶ 63,026, at P 204.

[24] *Id.* (quoting May 2000 Order, 91 FERC at 61,726).

[25] *Id.* at P 205 (citing July 2003 Order, 104 FERC at 61,726).

[26] Initial Decision, 106 FERC ¶ 63,026, at P 226 (citing May 2000 Order, 91 FERC at 61,726).

26. Next, the Initial Decision resolved the arguments that Amendment No. 27 is unjust, unreasonable, and unduly discriminatory because it does not specify the methodology for the allocation of FTRs. The judge noted that proposed section 4.5 of Appendix F, Schedule 3, of the ISO Tariff provided sufficient detail concerning the factors the ISO will consider in awarding FTRs to new Participating TOs, "while providing the ISO some flexibility in negotiating the number of FTRs with potential new [Participating] TOs."[27] This flexibility was necessary, the judge reasoned, because of the "significant differences in individual existing contracts."[28] However, the judge found that to ensure that market participants have a full opportunity to litigate the proposed award of FTRs,

> the ISO's tariff should be amended to require the ISO to file the proposed award with the Commission simultaneously with an amendment to the Transmission Control Agreement [] regarding each new [Participating] TO. . . . Such a tariff amendment will ensure that provisions regarding the award of FTRs to new [Participating] TOs will *not* affect any market participants until they are awarded, and *before that occurs*, every market participant will be provided notice of the proposed award and the opportunity to challenge it with full Commission review.[[29]]

This proposed amendment, the judge noted, was unopposed by the ISO.

2. <u>Exceptions</u>

27. TANC excepts to the Initial Decision's rejection of its proposal for the netting of usage charges. TANC contends that the purpose of FTRs is to provide a congestion hedge to the FTR holder. TANC argues that prior to becoming a new Participating TO, the entity had the ability to offset redispatch costs under its Existing Transmission Contract with revenues or savings from another period; under the ISO's proposal a new Participating TO is "worse off" because this ability to offset redispatch costs is eliminated.[30]

28. DWR excepts to the judge's holding that it is just and reasonable that FTRs for new Participating TOs terminate at the earlier of the end of the transition period or the termination of an existing contract. DWR asserts that it would be reasonable to terminate

[27] *Id.* at P 233.

[28] *Id.*

[29] *Id.* at P 234 (emphasis in original).

[30] TANC Brief on Exceptions at 44-45.

the provision of FTRs to new Participating TOs at the end of their existing contracts rather than at the end of the transition period. In DWR's view, FTRs provided to new Participating TOs at the conversion of their Existing Transmission Contracts should be coterminous with the Existing Transmission Contracts upon which they are based.

29. DWR also contends that the Initial Decision should be reversed concerning the methodology of the provision of FTRs. In this regard, DWR maintains the judge wrongly refused to require the ISO fully to explain its allocation of "commensurate" FTRs upon contract conversion. DWR argues that this conclusion contravenes Commission precedent on the issue.[31] Moreover, DWR asserts, the Initial Decision allows the ISO to negotiate its allocation of FTRs and related capacity in private, providing stakeholders only an after-the-fact announcement of the negotiating results.

3. Commission Determination

30. The Commission denies TANC's exceptions on the netting of usage charges. TANC's alternate proposal, as we understand it, would net FTRs with their associated revenues that were not used during one hour against the usage charges in other hours. Should TANC, for example, require additional transmission capacity during a congested period, this proposal would permit the use of FTRs unused in another hour to offset the usage charges during the congested period. Apparently, TANC compares this across-the-hours netting of revenue and charges to the situation under TANC's Existing Transmission Contract, where TANC can sell power under a back-to-back buy-sell transaction and use that revenue to offset any usage charges TANC might accrue in other hours. Moreover, such revenues from these back-to-back buy-sell transactions are not applied to TANC's TRR.

31. As a new Participating TO, TANC would be allowed to sell its unused FTRs at auction, but the revenue from such sales would be applied to TANC's TRR. This option would not allow TANC to "hold on to" revenue gained from the sale of FTRs to offset the usage charges assessed during periods of congestion. Therefore, TANC proposes a third option as a new Participating TO (besides either using its FTRs or selling them at auction): TANC apparently proposes to use the associated revenue from any "extra" FTRs to offset usage charges during other congested hours. Because TANC might continue to engage in the back-to-back buy-sell transactions as a new Participating TO in which TANC previously had engaged under its existing contract, it would appear that TANC remains virtually unaffected by the conversion of its Existing Transmission Contract and grant of free FTRs.

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[31] DWR Brief on Exceptions at 8 (arguing that "[l]ongstanding FERC precedent and regulations demand transparency from transmission providers concerning allocation of transmission entitlements"); *see also* Initial Decision, 106 FERC ¶ 63,026, at P 228.

32. The free distribution of section 9.4.3 FTRs is intended to approximate the benefits new Participating TOs held under their existing contracts, not to protect them from all market risk or congestion costs. The Commission finds that the ISO's proposed revised definitions of New Firm Transmission Right Revenue and Transmission Revenue Credit ensure that new Participating TOs receive the full benefit of the hedge against congestion provided by section 9.4.3 FTRs. In fact, under the ISO's proposal, the former use-it-or-lose-it right to capacity under the Existing Transmission Contracts would be replaced by an arguably more advantageous crediting mechanism for unused FTR revenue, under which unused FTRs would be credited to the entity's TRR. It seems to us that if the netting of usage charges against usage charge revenues were permitted across all hours, as TANC argues, TANC would be placed in a better position than it had originally been under its existing contracts. In any event, an entity that believes that its rights to offset redispatch costs are greater under its Existing Transmission Contracts than under this program of FTR allocation should factor that into any decision to become a Participating TO. Accordingly, we find that use of FTRs under section 9.4.3 of the ISO Tariff to provide new Participating TOs a financial hedge against usage charges is just and reasonable and appropriately conveys no financial advantage beyond this particular and limited purpose.

33. The Commission rejects DWR's argument concerning the termination of FTRs and affirms the Initial Decision on this issue. By converting its existing contract rights, a new Participating TO is fundamentally altering its status and must ultimately participate in the same FTR auction process as the original Participating TO. Original Participating TOs do not receive any free, unauctioned FTRs, yet their obligation to pay for purchased transmission continues until their purchase contract expires. The Commission recognizes the importance of this temporary incentive of providing free FTRs during the transition period as a benefit of becoming a Participating TO, but also that the disparate treatment of original and new Participating TOs eventually should end. The Commission finds that the termination of the award of free FTRs under section 9.4.3 of the ISO Tariff at the earlier of the end of the transition period or of an Existing Transmission Contract is just and reasonable.

34. We also deny DWR's exception on the methodology issue. As we have previously observed, in determining the precise number of FTRs to allocate, the ISO requires a measure of flexibility. The ISO agrees that before such FTRs are issued to new Participating TOs, the proposed award will be published, there will be an opportunity to protest, and the issued FTRs will be subject to the Commission's Standards of Conduct requirements. Accordingly, we find that section 9.4.3 and section 4.5 of Appendix F, Schedule 3, of the ISO Tariff provide sufficient detail for the allocation of FTRs to new Participating TOs provided that the ISO files simultaneously with the Commission the amendment to the Transmission Control Agreement regarding each new Participating TO.

35. The Commission affirms all other findings and conclusions of law of the presiding judge concerning FTRs.

36. The Commission finds that the award of section 9.4.3 FTRs to new Participating TOs who build High Voltage transmission facilities after becoming Participating TOs is inconsistent with the limited purpose of such allocations to encourage expansion of the ISO; therefore, the Commission will direct the ISO to clarify that ISO Tariff section 9.4.3 does not permit such allocation.

37. The Commission also will direct the ISO to amend ISO Tariff section 7.3.1.6 to reflect that, where a new Participating TO has been awarded section 9.4.3 FTRs over a jointly-owned interface with an original Participating TO, the new Participating TO should not participate in the disbursement of usage charges based on capacity for which the ISO has not issued FTRs; such participation would over-compensate the new Participating TO.

38. In order to account for the two roles of original Participating TOs as transmission owners and load serving entities, we will direct the ISO to amend ISO Tariff section 7.3.1.7, i.e., the definition of Transmission Revenue Credits.

D. <u>High-Low Voltage Split</u>

1. <u>Initial Decision</u>

39. The ISO originally proposed that the division of costs for substations and substation equipment (except step-down transformers) would adhere to the following three-step test: (1) if the Participating TO has substation TRR information by facility and voltage, then the TRR for facilities and equipment at or above 200 kV should be allocated to the High Voltage TRR and the TRR for facilities and equipment below 200 kV should be allocated to the Low Voltage TRR; (2) if the Participating TO has substation TRR information by facility but not by voltage, then the TRR for facilities and equipment should be allocated to the High Voltage TRR and to the Low Voltage TRR based on the ratio of gross substation investment allocated to High Voltage TRR to gross substation investment allocated to Low Voltage TRR pursuant to Step 1; and (3) if the Participating TO does not have substation TRR information by facility or voltage, then the TRR for facilities and equipment should be allocated to the High Voltage TRR and to the Low Voltage TRR based on the Participating TO's transmission system-wide gross plant ratio. However, the ISO proposed that costs for transformers that step down power from High Voltage to Low Voltage, to the extent the Participating TO does not have the revenue requirement information available on a voltage basis, should be allocated fifty percent to the High Voltage TRR and fifty percent to the Low Voltage TRR.

40. In addition to the ISO's division of cost proposal, PG&E recommended procedures for dividing the Transmission Revenue Balancing Account[32] between High Voltage TRR and Low Voltage TRR to ensure that the High and Low Voltage allocation is just, reasonable, and not unduly discriminatory. Finally, PG&E proposed that all system interconnections, both above and below 200 kV, should be included in a Participating TO's High Voltage TRR because these facilities provide unique, grid-wide benefits by facilitating the transmission of electricity between control areas.

41. The Initial Decision found the ISO's proposed allocation of the costs of transmission facilities between the High Voltage TRR and the Low Voltage TRR to be reasonable, with one exception. The presiding judge rejected the ISO's proposed 50/50 allocation of step-down transformer costs as arbitrary and inconsistent with cost causation principles. She further concluded that the record contained no support for the proposition that step-down transformers serve High Voltage and Low Voltage functions equally. Therefore, the presiding judge adopted Staff's alternative proposal, i.e., that where there is insufficient information available to allocate step down transformer costs between High Voltage TRR and Low Voltage TRR, these costs should be allocated in the same manner as other substation facilities. In the judge's view this allocation reasonably reflected the relative investment of transmission owners in High Voltage and Low Voltage facilities and was consistent with the ISO's allocation procedures for other substation facilities. Further, the presiding judge concluded that this allocation should be applied prospectively.

42. Accordingly, the presiding judge rejected PG&E's proposal to allocate the costs of system interconnections transmission facilities that interconnect High Voltage transmission facilities of a Participating TO with the transmission facilities of a neighboring control area "system interconnections" entirely to the High Voltage TRR.

43. Additionally, the presiding judge found that the ISO's procedures for the division of costs between High and Low Voltage transmission charges must be included in the ISO Tariff.

2. <u>Exceptions</u>

44. On exceptions, PG&E argues that the Initial Decision (1) failed to address PG&E's proposal with respect to dividing the Transmission Revenue Balancing Account between High Voltage TRR and Low Voltage TRR to ensure that the allocation is just,

[32] The Transmission Revenue Balancing Account is a mechanism established by each Participating TO that will ensure that all Transmission Revenue Credits and other credits flow through to transmission customers.

reasonable, and not unduly discriminatory, (2) erred in rejecting the ISO's proposed 50/50 allocation of step-down transformer costs to High Voltage TRR and Low Voltage TRR, and (3) erred by prohibiting Participating TOs from including all system interconnections in their High Voltage TRR.

3. <u>Commission Determination</u>

45. We agree with PG&E's contention that the Initial Decision (apparently inadvertently) failed to address its proposal for the appropriate division of the Transmission Revenue Balancing Account between High and Low Voltage TRRs. PG&E's recommendation that the allocation of High Voltage Transmission Revenue Balancing Account be proportionate to the existing and new High Voltage TRR is reasonable and unopposed, and is therefore approved. Accordingly, the ISO is directed to file revised tariff sheets that reflect PG&E's proposal.

46. With respect to the proper allocation of costs for substations and substation equipment, the Commission affirms the Initial Decision. The record not only contains no support for PG&E's claim that the step-down transformers serve High and Low Voltage functions equally, but also fails to support its 50/50 allocation with any data. Therefore, the presiding judge reasonably adopted Staff's alternative proposal that where there is insufficient information available to allocate step-down transformer costs between High Voltage TRR and Low Voltage TRR, these costs should be allocated in accordance with the ISO's allocation procedures for other substation facilities.

47. The Commission also affirms the Initial Decision regarding the allocation of system interconnections. Under the ISO's TAC proposal, system interconnections that are below 200kV would be included in a Participating TO's Low Voltage TRR and system interconnections that are 200kV and above would be included in a Participating TO's High Voltage TRR. PG&E argues that all system interconnections, regardless of voltage, should be included in the High Voltage TRR. PG&E reasons that system interconnections perform the same basic function as the transmission facilities that are included in the High Voltage Access Charge, carrying bulk power, and thus should be included in its entirety in the High Voltage TRR. However, the record evidence supports the presiding judge's finding. As supported by Trial Staff and explained by the presiding judge, PG&E's proposal would be significantly more complicated and burdensome than the ISO's three-step approach. Indeed, PG&E's evidence indicates that it took over 170 person-hours to complete a study identifying such system interconnections on the PG&E system.[33]

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[33] *See* Ex. PGE-6 at 6.

48. The Commission also agrees with Trial Staff and the presiding judge that PG&E's proposal could lead to disagreements as to whether or not certain facilities should be treated as High Voltage, adding inordinate uncertainty and complexity to the process. In Exhibit PGE 6-1, PG&E lists what it considers interconnection facilities. However, there is no explanation for how the allocation factor is determined, nor is there an explanation of how PG&E determined which lines to include and which are dual function.

49. Finally, we disagree with PG&E's argument that its determination of what should be included as system interconnection facilities would be a one time occurrence and that its list would not change going forward. As the Commission has seen in California, new control areas have been created and there are proposals for the creation of more. Most likely then, the determination of what facilities should be considered system interconnection facilities will continue to change. Accordingly, the Commission affirms the Initial Decision on this issue.

50. The Commission also affirms the presiding judge's finding that the ISO's procedures for the division of costs between High and Low Voltage transmission charges must be included in the ISO Tariff.

E. Cost Shift Caps

1. Initial Decision

51. The May 2000 Order instructed the presiding judge in this proceeding to determine whether the annual limitation or "cap" for each of the original Participating TOs (i.e., $32 million each for PG&E and SoCal Edison, and $8 million for SDG&E) and the proposed ten-year transition period from a license-plate rate structure to a single grid-wide rate, both of which are intended to operate in tandem with other components of the ISO's proposed transition mechanism, were just, reasonable, and not unduly discriminatory. In this order, the Commission recognized that, "[g]enerally, the use of transition periods are to mitigate large cost shifts and rate effects" and, therefore, the Commission required that "the record include, on a broader level, information on the overall impact of changes in transmission costs on the overall cost of electricity."[34] This order also stated that "the potential benefits that would inure to the customers of the original Participating TOs from the expansion of the transmission grid should also be considered in the selection of a reasonable transition period and the proper cap on cost shifts."[35]

52. In the Initial Decision, the presiding judge considered estimates submitted by parties regarding the amount of rate shock to be expected from the proposed cost shift cap. Specifically, the judge cited to the testimony of SDG&E witness Lucero who stated

[34] *See* May 2000 Order, 91 FERC at 61,725.

[35] *Id.*

that, "if LADWP and other [Governmental Entities] do not join [the ISO], the overall impact per MWh over a four-year period ranges from 0.40 to 0.52 percent."[36] Likewise, Trial Staff witness Patterson testified that, "given the unlikely scenario that all non-jurisdictional entities in California would elect to join the ISO," the estimated average increase per MWh to the original Participating TOs retail customers would be approximately 0.40 percent. And even given full participation, Trial Staff witness Patterson estimated cost shifts to be one percent at most.[37]

53. The Initial Decision rejected PG&E's contention that the effects of rate shock should be measured as it pertains to transmission, rather than energy costs as a whole, leading to estimates that original Participating TOs could face transmission cost increases of between twenty and fifty percent.[38] However, the presiding judge rejected PG&E's argument as beyond the scope of the Commission's mandate. She also rejected PG&E's reliance on cases in which the Commission approved cost shift caps and transition periods to mitigate rate shock in transmission rates on the ground that in those cases the transition period was shorter than the ten-year transition period proposed here.[39] "Here," the judge reasoned, "the longer transition period will serve to mitigate any small amount of rate shock that does occur."[40] In sum, the presiding judge found that retaining the cost shift cap was unjustified and, therefore, concurred with Staff witness Patterson's recommendation to eliminate the cost shift cap on a prospective basis.

54. Concerning the ISO's proposed "hold harmless" provision, the judge expressed concern that eliminating the cost shift cap would tip this balance in favor of the new Participating TOs, if the hold harmless provision was not similarly eliminated. Retaining the hold harmless provision in this circumstance, the judge determined, would essentially protect new Participating TOs from a cost shift and not provide the same protection for the original Participating TOs' customers, "who would then pay increased rates to compensate any new Participating TO whose transmission rates are greater than the TAC rate as a result of joining the ISO."[41] The Initial Decision thus concluded that rejecting the cost shift cap as unjustified meant that the hold harmless provision should be similarly rejected.

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[36] Initial Decision, 106 FERC ¶ 63,026, at P 148 (citing Ex. SDGE-2 at 12:16).

[37] *Id.* at P 148 (citing Ex. S-5 at 28:25 to 29:3).

[38] *Id.* at P 149 (citing Ex. PGE-5 at 2:14 to 3:3 and Ex. PGE-5-1).

[39] In this context, PG&E relied on *GridFlorida, LLC*, 94 FERC ¶ 61,363, at 62,348-50 (2001); *Westconnect RTO, LLC*, 101 FERC ¶ 61,033, at P 122, 139, *on reh'g*, 101 FERC ¶ 61,350 (2002); *Alliance Companies*, 99 FERC ¶ 61,105, at 61,144 (2002).

[40] Initial Decision, 106 FERC ¶ 63,026, at P 149.

[41] *Id.* at P 151 (citing PG&E's Initial Brief at 6, 21).

55. Next, the presiding judge entertained arguments regarding alternative cap proposals. PG&E proposed to modify the ISO's proposal so that a new Participating TO could not recover more than twenty-five percent of its High Voltage TRR from the original Participating TOs' customers. PG&E argued that this proposal would mitigate the elimination of the "buy-down" provision from the Amendment No. 49 proposal, and still foster participation in the ISO while balancing the burden on original Participating TOs.[42] SoCal Edison argued further that the Commission's elimination of the buy-down provision from the TAC proposal has resulted in increased costs to the original Participating TOs and, therefore, SoCal Edison proposed to lower the cap (i.e., $20 million each for PG&E and SoCal Edison and $5 million for SDG&E, or cost shift caps of $6 million each for PG&E and SoCal Edison and $2 million for SDG&E if no new Participating TOs join the ISO) and raise the transition period to twelve years.[43]

56. The presiding judge reasoned that alternative proposals rested on the rationale that several components of the TAC had changed since the original proposal. However, the presiding judge believed that "the TAC must be evaluated as the package it is today, not the package it is today compared to how it was when it was proposed." [44] On this basis, she concluded that "the record does not demonstrate the likelihood of a rate shock sufficient enough to justify any cost shift cap or longer transition period."[45]

57. The ISO proposed excluding new High Voltage facilities from the calculation of the transition charge and the immediate inclusion of new High Voltage facilities in the grid-wide component of the High Voltage Access Charge. The ISO argued that these two proposals do not discriminate against any Participating TO class (i.e., owners of existing High Voltage facilities placed in service prior to January 1, 2001, as opposed to owners of new High Voltage facilities placed in service after January 1, 2001) because the utilities proposing to build new High Voltage facilities are not similarly situated to

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[42] In Amendment No. 27, the ISO proposed a buy-down provision which required new Participating TOs to use any TAC benefits they received to amortize or write-off investment in High Voltage transmission facilities equal to the savings realized from the TAC benefit. However, in the May 2000 Order the Commission rejected this provision for three reasons: (1) the ISO did not demonstrate that the buy-down proposal was reasonable; (2) for jointly-owned facilities, the buy-down provision could result in an accelerated book amortization for a new Participating TOs' portion of the jointly-owned facilities, while the original Participating TO would pay a lesser accelerated depreciation for its portion; and (3) the buy-down provision was inconsistent with the goals of Order No. 2000 and would discourage participation in ISOs. May 2000 Order, 91 FERC at 61,727-28.

[43] Initial Decision, 106 FERC ¶ 63,026, at P 153 (citing Ex. SCE-1 at 22-23 and Ex. SCE-5 at 40-43).

[44] *Id.* at P 163.

[45] *Id.*

utilities with existing High Voltage facilities.[46] The ISO further observed that the new High Voltage facilities were built in conjunction with and with the approval of the ISO to benefit the entire ISO-controlled grid. Moreover, if the two classes were viewed by the Commission as similarly situated, the ISO argued that the difference in treatment is justified to encourage the financing of transmission expansions.

58. The presiding judge adopted both of the ISO's proposals.[47] She adopted the position, advanced by Trial Staff, that this was not unduly discriminatory because, if new Participating TOs build new facilities, those facilities will be treated in the same manner as original Participating TOs new facilities and their costs will be rolled-in grid wide. Therefore, due to the non-discriminatory nature of the provision and the removal of a cap on how much the new Participating TOs can spend to upgrade or add new facilities, the presiding judge found the claims opposing the provision to exclude existing High Voltage facilities from the transition charge to be unpersuasive.

2. <u>Exceptions</u>

59. In their respective briefs on exception, TANC and Modesto assert that the Initial Decision was correct in rejecting the cost-shift cap, but erred with respect to the basis of this rejection: the lack of a demonstrable rate shock. Both parties argue that the presiding judge's finding should have reflected that the cost shift cap is unduly discriminatory as applied to new and potential new Participating TOs and, thus, should be rejected on that basis. TANC asserts further that the Initial Decision established that abrupt cost shifts do not exist and, therefore, the transitional distinction is unnecessary. Accordingly, TANC argues that, since the ISO acknowledged that the cost shift cap treats original Participating TOs and new Participating TOs differently, but failed to adequately support this difference, the cost shift cap must be rejected as unduly discriminatory.

60. PG&E alleges that the Initial Decision erred by ignoring the benefit and burden issue with regard to the cost shift cap. Specifically, PG&E claims that, while the Initial Decision discusses at length the issue of rate shock, there is no mention of any benefits the original Participating TO customers receive that justifies eliminating the cost shift cap, which, PG&E claims, was agreed to by a broad coalition of ratepayers and stakeholders. PG&E reiterates that the cost shift cap is, in fact, just and reasonable because all parties agree that cost shifts have occurred and will continue to occur. Moreover, original Participating TO customers will pay millions of dollars in cost shifts even though these customers are using less than 3.8 percent of the capacity turned over by

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[46] High Voltage facilities built before January 1, 2001, are considered existing High Voltage facilities, while those build after January 1, 2001, are considered new High Voltage facilities.

[47] Initial Decision, 106 FERC ¶ 63,026, at P 174.

four of the five new Participating TOs, which, in PG&E's opinion, makes these cost shifts significant and unrelated to the services provided. As such, PG&E finds that a mitigation measure such as the cost shift cap is both just and reasonable.

61. PG&E further asserts that the Initial Decision erred in ignoring the evidence of impact of changes in transmission costs. Specifically, PG&E faults the judge for disregarding its evidence of projected increases in transmission rates to be between twenty and fifty percent for original Participating TO customers. Finally, PG&E claims that the Initial Decision's reliance on the duration of the transition period to mitigate cost shifts lacks evidentiary support. PG&E asserts that it is the cost shift cap itself, and not the duration, that is intended to limit cost shifts during the transition period.

62. SoCal Edison also excepts to the Initial Decision on this issue. SoCal Edison argues that it is irrelevant whether or not a proposed rate increase can cause rate shock, unless such a rate increase first complies with the just and reasonable standard set forth in the Federal Power Act.[48] SoCal Edison claims that the Initial Decision completely reverses this analysis and ignores considerations of whether the proposed TAC rate increase to the original Participating TOs, with or without a cost shift cap, is just and reasonable. For these reasons, SoCal Edison asserts that the cost shift cap should be evaluated based on the transmission components of retail rates.

63. In addition, SoCal Edison argues that the presiding judge failed to examine the balance of the costs and benefits of the new rate methodology on the ratepayers of both the new and original Participating TOs. Regardless of whether it is appropriate to give consideration to the impact of the TAC cost shift on the total-delivered-energy price, SoCal Edison states that long-standing Commission policy requires that the impact of a proposed increase in transmission rates also must be reviewed, in terms of its impact, on just the transmission component of rates.[49] Moreover, according to SoCal Edison, since transmission costs are a relatively small component of energy costs, the presiding judge's reliance on a one percent threshold would allow virtually any proposed increase in transmission rates to be set at a just and reasonable level. Finally, SoCal Edison believes that the presiding judge's findings support its argument that the cost shift cap proposed by the ISO was set too high and should have been reduced.

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[48] 16 U.S.C. § 824d (2000).

[49] SoCal Edison Brief on Exceptions at 13 (citing *Commonwealth Edison Co.*, 105 FERC ¶ 61,186 (2003), and *Avista Corp.*, 100 FERC ¶ 61,274 (2002)).

3. Commission's Determination

64. In evaluating the justness and reasonableness of the cost shift cap proposal, the Commission's May 2000 Order required that "the record *include*, on a broader level, information on the overall impact of changes in transmission costs on the overall cost of electricity."[50] In addition, the presiding judge was asked to consider "the potential benefits that would inure to the customers of the original Participating TOs from the expansion of the transmission grid . . . in the selection of a reasonable transition period and the proper cap on cost shifts."[51] However, we agree with the parties who have argued that our guidelines did not eliminate the need for the cost shift cap to be evaluated under the just and reasonable standard of the Federal Power Act. Thus, a key question is whether the potential increase in costs to the original Participating TOs' ratepayers reasonably justifies the proposed cost shift cap.

65. The Commission finds that the Initial Decision viewed this issue too narrowly by limiting her consideration of potential impact of transmission costs solely relative to the total cost of electricity. Indeed, on cross-examination, Trial Staff witness Patterson affirmed that "[n]ormally, [in examining a proposed transmission rate increase], the Staff . . . considers the impact of the proposed transmission increase on the transmission component of the retail rate."[52] Because of this incorrect premise, the presiding judge did not consider those portions of the record that evaluated the cost shift cap on actual transmission costs. Therefore, we will discuss the merits of certain exhibits submitted by the ISO, PG&E, and SoCal Edison that did not receive due consideration in this proceeding.

66. In Exhibits PGE-5 at 2:14 to 3:3 and PGE-5-1, PG&E provides an analysis of rate shock to the original Participating TOs' customers as it pertains to transmission only. Specifically, PG&E's analysis considers the increase in High Voltage transmission service costs of TO Tariff customers of the original Participating TOs. In Exhibit PGE-5-1, PG&E concludes that these customers will bear increases of twenty to fifty percent in High Voltage Access Charges over the costs that they would otherwise pay for transmission under utility-specific rates, if the TAC proposal is approved without imposing cost shift caps.[53] Additionally, PG&E witness Kozlowski refers to Staff Exhibit S-13 as conceding that "the customers who will bear these cost shifts have also

[50] May 2000 Order, 91 FERC at 61,725 (emphasis added).

[51] *Id.*

[52] Tr. at 2739.

[53] In her cross-answering testimony, PG&E witness Kozlowski states that, in preparing her analysis, she used the same scenarios regarding the number of Participating TOs in the ISO market as Trial Staff witness Patterson. *See* Exhibit PGE-5-1.

suffered increases in MWh energy costs of 20 percent for SoCal Edison, 42 percent for PG&E and 110 percent for SDG&E from 1999 to 2002."[54] In Exhibit SCE-13, SoCal Edison's witness Cullier concluded in his cross-answering testimony that seventy to eighty percent of the new Participating TOs' High Voltage transmission costs are being paid by the original Participating TOs and, therefore, the original Participating TOs must collect eleven to sixteen percent in higher rates from their own retail ratepayers.

67. The Commission agrees with Trial Staff witness Patterson, who testified under cross-examination that the increases cited above constitute a significant change in the original Participating TOs' transmission rates.[55] We believe that the record in this proceeding clearly demonstrates that a significant cost shift has occurred and will continue to occur through the transition period.

68. The question then becomes whether, in light of this record, the cost shift cap is just and reasonable. The Commission finds that that, in view of the magnitude of the potential costs shifts, the answer is yes. Further supporting our conclusion is the matter of balancing the benefits and burdens of the new and original Participating TOs. Exhibit ISO-18 provides evidence on this point. There, ISO witness Pfeifenberger illustrates that in 2001 and 2002, annual cost shifts associated with the revised TAC methodology were approximately $7 million accruing to the City of Vernon as a benefit and as a TAC-related burden to the original Participating TOs. In Table 2 of Exhibit ISO-20, the cost shifts increase to approximately $42 million with the advent of four new participants—the Cities of Anaheim, Azusa, Banning, and Riverside. This exhibit also predicts that under a full membership scenario cost shifts could range from close to $130 million to over $170 million per year for the 2004 through 2010 transition period. Additionally, Amendment No. 27 rewards new Participating TOs with "free" FTRs, quick withdrawal from the ISO if their tax-exempt status of their financing is affected, Reliability Must Run cost allocation exemption, and Metered Subsystem treatment, among other things.

69. In this regard, the Commission observes that original Participating TOs were to benefit through the buy-down provision, placing caps on the amount of cost shifts experienced by each original Participating TO, and phasing in the shift from TAC area rates to an ISO-controlled grid-wide rate over ten years. However, our elimination of the buy-down provision in Amendment No. 27 Order altered the balance of the transitional package of benefits. We believe that removing the cost shift cap, another significant piece of this package, would unreasonably skew the equation of benefits and burdens vis-à-vis the new and original Participating TOs.

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[54] PG&E witness Kozlowski recognizes that Exhibit S-13 is an incomplete analysis because it does not reflect all of the sales of SDG&E's customers during the test period. *See* Exhibit PGE-5-1.

[55] Tr. at 2740.

70. The Commission finds TANC's assertion that the cost shift cap must be rejected as unduly discriminatory to be without merit. The cost shift cap was proposed as an incentive to spur participation in the ISO. We believe that the ISO's primary goal—expanding the ISO-controlled grid while avoiding abrupt cost shifts—does in fact constitute a compelling reason warranting different treatment. Moreover, contrary to TANC's assertion, the disparate treatment here benefits new Participating TOs and not the original Participating TOs. Moreover, if the cap is exceeded, we believe it is reasonable for the new Participating TOs to continue to recover their respective TRRs from their ratepayers who would still benefit by paying significantly lower, pre-ISO costs. And, of course, the disparity of treatment is a temporary condition which will end with the termination of the transition period.

71. In sum, the Commission will reverse the presiding judge in this proceeding and accept the ISO-proposed 32:32:8 cost shift cap proposal. It follows that, to keep the balance of benefits and burdens steady, we will reverse the presiding judge's ruling with regard to the hold harmless provision. In addition, with regard to the alternative cap proposals submitted by PG&E and SoCal Edison at the hearing, our reversal of the presiding judge's ruling on this matter renders these alternative proposals moot.

72. With respect to the derivation of the 32:32:8 cost shift cap ratio, the ISO presented evidence in Exhibit ISO-5, that the Transmission Access Charge Working Group, which was comprised of market participants and ISO representatives met regularly since December of 1998, "attempted to identify and quantify the types of cost increases and savings each party will experience under an access charge/new Participating TO scenario." As a result of these sessions, the parties reached consensus on the 32:32:8 ratio for the cost shift cap. However, the basis for this ratio, along with data received by the ISO from the working group participants to perform cost/benefit and other analyses, "are subject to confidentiality rules similar to those used in settlement discussions."[56] The ISO has explained that this arrangement was a prerequisite for market participants to turn over commercially sensitive and confidential information. Accordingly, the working group participants agreed not to challenge the 32:32:8 cost shift cap ratio at the hearing. Additionally, as the Initial Decision notes, "the record contains no evidence of why they picked these particular numbers."[57]

73. The Commission finds that, in this particular case, we will give deference to these arrangements arrived at during the course of the stakeholder process. Generally, the stakeholder process assures that proposals are subject to scrutiny and based on in-depth analysis. In our judgment, based on the record before us, the cost shift cap and ratio

[56] Ex. ISO-5 at 3.

[57] Initial Decision, 106 FERC ¶ 63,026, at P 146 (citing Staff Initial Brief at 28; Ex. S-5 at 18:11-14).

selected during that process do not appear to produce an unreasonable result. In this context, we note that the selection of a specific dollar cap and accompanying ratio is by its nature difficult because all affected parties may value different components of an overall rate design package differently. Indeed, as previously noted, SoCal Edison now argues for a reduced dollar cap because of the Commission's disallowance of the ISO's buy-down proposal.

74. Finally, the Commission affirms the presiding judge's ruling regarding the exclusion of High Voltage transmission facilities from the transition charge and the immediate inclusion of High Voltage transmission facilities in the grid-wide component of the TAC for the reasons discussed in the Initial Decision.

II. The Partial Initial Decision and Motion to Reopen the Record

A. The Partial Initial Decision

75. On October 21, 2003, prior to beginning the hearing in this proceeding, the presiding judge issued a Partial Initial Decision,[58] resolving an issue arising from the ISO's proposal to amend section 3.1 of the ISO Tariff to state which facilities a new Participating TO should turn over to the ISO's operational control.[59]

76. Before the judge, DWR filed evidence concerning its contention that the ISO Tariff should "contain a clear description of the ISO's standards and criteria to determine [] whether facilities will be accepted for ISO Control and/or in ISO [TAC] rates."[60]

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[58] *Calif. Indep. Sys. Operator Corp.*, 105 FERC ¶ 63,008 (2003).

[59] In relevant part, section 3.1 of the ISO Tariff, as amended, states (amended language in italics):

> Each Participating TO shall enter into a Transmission Control Agreement with the ISO. In addition to converting Existing Rights in accordance with Section 2.4.4.2, New Participating TOs will be required to turn over Operational Control of all facilities and Entitlements that: (1) *satisfy the FERC's functional criteria for determining the transmission facilities that should be placed under ISO Operational Control*; (2) satisfy the criteria adopted by the ISO Governing Board identifying transmission facilities for which the ISO should assume Operational Control; and (3) is the subject of mutual agreement between the ISO and the Participating TOs.

[60] Partial Initial Decision, 105 FERC ¶ 63,008, at P 5 (quoting Ex. SWP-1 at 47:16-19).

DWR also proposed new standards to determine which facilities should be accepted for ISO Operational Control (and thus be included in the TAC). Under DWR's proposal, facilities classified as generation ties rather than as network transmission would be excluded from the calculation of the TAC, in accordance with an Initial Decision that had been issued in Docket No. ER99-2326.[61]

77. Subsequently, SoCal Edison filed a motion for partial summary disposition with respect to DWR's proffer. SoCal Edison contended that neither the determination of the costs of which facilities under ISO Operational Control should be included in a Participating TO's TRR nor the ISO's policy concerning which facilities can be turned over to ISO control were at issue in this proceeding.[62] SoCal Edison further asserted that the ISO's standards on these matters mirrored Commission policy and thus could not be unjust and unreasonable as a matter of law.

78. In ruling on this issue, the presiding judge took notice that the Initial Decision in Docket No. ER99-2326 had been reversed by the Commission in Opinion No. 466.[63] There, the Commission decided that the question of which facilities should be included in a Participating TO's TRR should be determined solely by whether control of the facilities had been turned over to the ISO.[64]

79. In the Partial Initial Decision, the judge granted SoCal Edison's motion for partial summary disposition, relying on the "clear language of the [Transmission Control Agreement], the ISO Tariff, and guidance provided by the Commission in Opinion No. 466."[65] The judge explained:

> [W]hile it is strongly recommended that the ISO also include in its Tariff the relevant language currently contained in its [Transmission Control Agreement] regarding the standard for facilities that could be turned over to ISO Operational Control, failure to have done so does not render the [Transmission Control Agreement] language any less clear or per se unjust and unreasonable. With the additional guidance provided by . . . Opinion No. 466, the [Transmission Control Agreement] was sufficient under the facts of this case to provide the parties with notice of the applicable ISO

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[61] *Pacific Gas and Electric Co.*, 97 FERC ¶ 63,014 (2001).

[62] The relevant sections of the Transmission Control Agreement are 4.1.1 and 4.1.3.

[63] *Pacific Gas and Electric Co.*, Opinion No. 466, 104 FERC ¶ 61,226 (2003).

[64] *Id.* at P 13.

[65] Partial Initial Decision, 105 FERC ¶ 63,008, at P 15.

> standard regarding the criteria and policy which guide the ISO's determinations of facilities over which it will exercise operational control, and correspondingly which facilities will be included in the ISO's transmission rates.[[66]]

B. Briefs on Exceptions

80. The California Public Utility Commission (California Commission) and DWR filed briefs on exceptions to the Partial Initial Decision. Briefs opposing exceptions were filed by the ISO, the Cities, and jointly by PG&E and SoCal Edison.

81. The California Commission essentially argues that the Partial Initial Decision errs by failing to take into account the underlying question of what types of facilities should be included in the TRRs of facility owners, in order to ensure just and reasonable ISO rates. The California Commission further faults this Commission for not developing "specific functional criteria to identify facilities that serve an integrated transmission function and those that do not."[67] In the California Commission's view, the judge's reliance on the Transmission Control Agreement in this instance is misplaced, as that document gives the ISO complete discretion as to whether or not it will accept control of facilities.

82. DWR similarly argues that the judge should not have relied exclusively on Opinion No. 466 for guidance, because that decision is inconsistent with Commission policy with respect to the appropriate ratemaking treatment for ISO-controlled facilities. DWR further maintains that its proposed evidence establishes the need for a clear standard in the ISO Tariff for determining which facilities may be turned over to ISO control.

C. The Motion to Reopen the Record

83. Subsequent to the filing of the briefs on the Partial Initial Decision, the Commission issued Opinion No. 466-A, which concluded that ISO operational control should not be the sole factor in deciding whether facilities should be included in a utility

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[66] *Id.* at P 16.

[67] California Commission Brief on Exceptions at 22. The California Commission notes that, at the time it filed its brief, Opinion No. 466 was subject to further review by this Commission.

owner's TRR (in this case, PG&E).[68] Instead, the Commission explained that it would also make an independent determination whether particular facilities served a transmission network function. Applying PG&E's proposed rolled-in methodology for classifying the facilities in question, Opinion No. 466-A concluded that all of the disputed facilities served a transmission function and should be included in the TRR.[69]

84. On July 27, 2004, DWR filed a motion in these dockets to reopen the record with respect to this issue. In support, DWR explains that because the Commission granted rehearing of Opinion No. 466,

> *the sole precedent* that formed the basis for excluding from the hearing the issue of the ISO's criteria for accepting operational control over facilities, and corresponding criteria for inclusion of the costs of such facilities in the ISO's jurisdictional transmission rates, has been vacated on rehearing.[[70]]

Thus, according to DWR, there has been a significant change in the law necessitating a reopening of the record because "there is now *no precedent and no reason* supporting summary disposition of what standards, if any, govern the transfer of facilities to ISO operational control and the inclusion of the corresponding costs in ISO access charges."[71]

85. DWR also argues that significant changes in conditions of fact warrant reopening the record. These changes are evidence introduced in other Commission proceedings,[72] which, DWR maintains, "demonstrate[] the need for the Commission to consider

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[68] *Pacific Gas and Electric Co.*, Opinion No. 466-A, 106 FERC ¶ 61,144 (2004). The Commission affirmed this decision in Opinion No. 466-B, which denied a request for rehearing by DWR concerning the criteria and evidence employed in our determination of which facilities served a network transmission function. *Pacific Gas and Electric Co.*, Opinion No. 466-B, 108 FERC ¶ 61,297 (2004).

[69] The Commission reversed the judge with respect to two categories of the facilities at issue, which he had determined should be classified as generation and thus excluded from the TRR.

[70] DWR Motion to Reopen Record at 6 (emphasis in original).

[71] *Id.* at 8 (emphasis in original).

[72] *City of Vernon, California*, Docket No. EL00-105 (*Vernon*); *City of Anaheim California*, Docket No. EL03-15 (*Anaheim*); and *City of Riverside, California*, Docket No. EL03-20 (*Riverside*).

transparent criteria governing the facilities over which the ISO may take operational control," and thus the inclusion of costs in the Participating TOs' TRRs and "ISO transmission rates."[73]

86. Answers opposing DWR's motion were filed by the ISO, the Cities, PG&E, SoCal Edison, Vernon, and Trial Staff.

D. Commission Determination

87. The Commission affirms the Partial Initial Decision. DWR filed testimony intended to prove that the ISO Tariff should contain a clear description of the ISO's standards and criteria to determine whether facilities will be placed under ISO control and thus included in the TAC. The fundamental question in this proceeding, of course, is whether the ISO's proposed amendment to its tariff establishing the TAC methodology is just and reasonable. It is true that included in this proposal is an amendment to the ISO Tariff (quoted above) which briefly refers to the issue of which facilities should be turned over to ISO control. However, the ISO's policy with respect to which facilities it should operate is primarily addressed in its Transmission Control Agreement, which is not at issue here. The proposed amendment to the ISO Tariff merely makes reference to the appropriate provisions of the Transmission Control Agreement and Commission policy on the issue.

88. Furthermore, Commission policy on the issue of which facilities should be included in the Participating TOs' TRRs should be and is being decided in their individual TRR proceedings. For example, the question of which facilities should be included in PG&E's TRR, and how this determination should be made, was decided in Docket No. ER99-2326, in Opinion Nos. 466, 466-A, and 466-B. Thus, the presiding judge was on firm ground in holding that the relevant amendment to the ISO Tariff was just and reasonable, and rejecting DWR's attempt to pursue an issue at best tangentially related to this case.

89. It follows from our affirming of the Partial Initial Decision that DWR's motion to reopen the record must be denied. The fact that the Commission revised its findings regarding the proper manner to determine which facilities should be included in the Participating TOs' TRRs in Opinion Nos. 466 and 466-A, has no bearing here. In any event, Order No. 466-A clearly sets out Commission policy concerning which facilities should be included in the Participating TOs' TRRs.

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[73] DWR Motion to Reopen Record at 9.

90. More importantly, as we have already discussed, the issue pressed by DWR is being decided elsewhere. Thus, DWR's attempt to introduce new evidence concerning the costs properly included in the new Participating TOs' TRRs must be rejected. That question should be and will be decided in the *Vernon*, *Anaheim*, and *Riverside* proceedings, and is irrelevant to this case.

III. Issues Arising from the July 2003 Order

A. The July 2003 Order

91. As relevant here, the ISO had proposed that "the TAC would be payable on each MWh of energy withdrawn from the ISO controlled grid; thus entities would pay for transmission based on the amount of gross load."[74] In the July 2003 Order, the Commission approved this proposal, rejecting an objection by several Governmental Entities that behind the meter generation should not be subject to the TAC. However, the Commission established an exception to the allocation of the TAC on a gross load basis for behind the meter generation, based on a similar exception established in Opinion No. 463 for the ISO's Control Area Services portion of its Grid Management Charge.[75] In accordance with Opinion No. 463, we found that:

> customers that primarily rely on behind the meter generation to meet their energy needs are allocated too great a share of the TAC. Instead, these customers should pay the TAC on a net load basis, i.e., the actual cumulative kWh load that utilized the grid on any given month, to reflect their use of the grid to access alternative resources, rather than on the basis of gross load. As with the [Grid Management Charge], customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor.[[76]]

The July 2003 Order directed the ISO to submit a compliance filing on this issue.

B. The ISO's Compliance Filing and the Parties' Requests for Rehearing

92. On July 25, 2003, the ISO submitted its compliance filing. Notice of the ISO's filing was published in the *Federal Register*, 68 Fed. Reg. 46,597 (2003), with motions to

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[74] July 2003 Order, 104 FERC ¶ 61,062, at P 49. The proposal recognized an exception for Qualifying Facilities meeting certain criteria.

[75] *Calif. Indep. Sys. Operator Corp.*, Opinion No. 463, 103 FERC ¶ 61,114 (2003).

[76] July 2003 Order, 104 FERC ¶ 61,062, at P 55 (footnote omitted).

intervene, comments and protests due on or before August 15, 2003. Protests to the ISO's compliance filing were filed by SWC/Metropolitan, Modesto, and SoCal Edison; NCPA filed comments.

93. Additionally, timely requests for rehearing and/or clarification of the July 2003 Order were filed by the ISO, Modesto, SoCal Edison, TANC, and Vernon,[77] primarily concerning the inclusion of behind the meter generation in the TAC's transmission billing determinants, and the exception to gross load treatment established by the Commission.

94. On rehearing, the ISO argues that the Commission erred by establishing an exception for behind the meter generation, and asks that it "reinstate its initial conclusion that the ISO's [TAC] should be assessed to all Participating Transmission Owners . . . on the basis of Gross Load."[78] In the ISO's view, allowing behind the meter load to avoid paying a full share of the costs of transmission facilities for what is essentially network service "merely shifts costs to other users of the ISO Controlled Grid."[79] In this context, the ISO asserts that the holding here is inconsistent with the Commission's decision that load served by a generator to which it was directly connected to a Participating TOs' distribution system should not be exempted from the TAC.[80]

95. The ISO further contends that if the exemption from the TAC is limited to Governmental Entities, the result unduly discriminates against the loads of investor-owned utilities.[81] Finally, the ISO seeks clarification concerning the method by which the capacity factor referred to in the exemption should be determined.

96. Modesto likewise seeks clarification with respect to the behind the meter exemption from gross load allocation. Specifically, Modesto asks the Commission to clarify that customers serving no more than fifty percent of their behind the meter load from the ISO-controlled grid qualify to pay their TAC based on net load, i.e., the actual

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[77] On August 18, 2003, SoCal Edison filed a response to Vernon's request for rehearing. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2004), prohibits an answer to a request for rehearing unless otherwise ordered by the decisional authority. We are not persuaded to accepted SoCal Edison's answer and will, therefore, reject it.

[78] ISO Request for Rehearing at 1.

[79] *Id.* at 7.

[80] *Id.* at 7-8 (citing *Pacific Gas and Electric Co., et al.*, 88 FERC ¶ 63,007, at 65,075 (1999), *aff'd*, 100 FERC ¶ 61,156, *reh'g denied*, 101 FERC ¶ 61,151 (2002)).

[81] SoCal Edison also makes this argument in its request for rehearing.

cumulative load that utilized the ISO grid in any given month.[82] In the alternative, if this was not the Commission's intent, Modesto requests that the Commission grant rehearing on this issue. Additionally, Modesto seeks "clarification" that by establishing the behind the meter exception, the Commission was mistaken in setting for hearing the issue of whether exclusion of QFs who pay a standby charge that includes a transmission component from the TAC charge is unduly discriminatory with respect to non-QFs with behind the meter generation.

97. Modesto also requests clarification from the Commission that it did not intend to prejudge the resolution of the ISO's MD02 market redesign (now referred to as MRTU) proposal by its description of that proposal eliminating phantom congestion while honoring the rights of Existing Transmission Contract holders.[83]

98. Like the ISO, SoCal Edison argues that the Commission erred in departing from a straightforward gross load assessment of the TAC. Additionally, SoCal Edison argues that the fifty percent capacity factor test should be rejected as arbitrary.

99. Vernon asserts that the Commission erred in stating that "the issues of what approach and standard to use" concerning a Governmental Entity's TRR "will not be decided here" because they are pending in Docket EL00-105.[84] According to Vernon, because the Commission is only considering Vernon's TRR "in the referenced remand proceeding[,]" the Commission should not in that proceeding "establish the treatment to be accorded all governmental entity TRR filings to come."[85]

C. Commission Determination

1. The Behind the Meter Exception

100. To a significant extent, the parties' arguments concerning the exception to allocating the TAC on a gross load basis for customers primarily relying on behind the meter generation has been overtaken by events. As discussed above, the exception

[82] TANC also makes this argument in its request for rehearing.

[83] Modesto Request for Rehearing at 5 (citing July 2003 Order, 104 FERC ¶ 61,062, at P 41).

[84] Vernon Request for Rehearing at 1 (quoting July 2003 Order, 104 FERC ¶ 61,062, at P 22).

[85] *Id.* at 3.

established by the July 2003 Order was based on the analogous exception in Opinion No. 463 concerning assessment of the Control Area Services component of the ISO's Grid Management Charge.

101. Subsequently, however, the Commission issued Opinion No. 463-A, which concluded that the exception for those customers with a fifty percent or greater capacity factor was not supported by record evidence and created implementation problems.[86] Therefore, Opinion No. 463-A created an exception from the use of Control Area Gross Load allocation for "generators which are not modeled by the ISO in its regular performance of transmission planning and operation."[87]

102. A number of parties sought rehearing concerning Opinion No. 463-A's gross load exception. As a result, on November 16, 2004, the Commission issued an order deferring the rehearing requests, and establishing limited hearing procedures.[88] In that order, we affirmed our finding that the assessment of the Control Area Services charge based on Control Area Gross Load was just and reasonable. We likewise "continue[d] to subscribe to the concept of an exception from Control Area Gross Load based on whether the generator and associated behind the meter load are modeled by the ISO."[89] However, the Commission went on to find that because it had established the exception on a *sua sponte* basis, questions concerning the exemption and its administration that could not be resolved on the record compiled in the course of the proceeding. We therefore set the specific issue for an expedited hearing (with an Initial Decision to be issued by April 15, 2005).

103. This brings us to the behind the meter gross load exception the Commission created for the TAC in the July 2003 Order. Once again we acted *sua sponte*, in accord with Opinion No. 463, and perhaps, as in that case, a little too precipitously. We believe that the issue of whether the behind the meter exception that we have applied to the Control Area Services portion of the Grid Management Charge, by means of which the ISO collects its administrative costs, is appropriate in the context of the TAC, a transmission charge designed to collect the embedded transmission costs of the ISO-

[86] *Calif. Indep. Sys. Operator Corp.*, Opinion No. 463-A, 106 FERC ¶ 61,032 (2004).

[87] *Id.* at P 20.

[88] *Calif. Indep. Sys. Operator Corp.*, 109 FERC ¶ 61,162 (2004) (November 2004 Hearing Order).

[89] *Id.* at P 15.

controlled grid, requires further analysis. In view of the ongoing hearing on the issue in the GMC case, the Commission has decided to defer decision on the gross load exception issue here pending our review of the record compiled in that proceeding.

2. Other Issues

104. With respect to the remaining live issues, the Commission clarifies that we did not intend to limit any exemption from the TAC to be limited to Governmental Entities.

105. Modesto's requests for clarification are denied. First, it should be obvious that the Commission did not intend to prejudge the resolution of the ISO's market redesign which will be resolved in the MRTU (formerly, MD02) proceeding, and no clarification is required. Second, the Qualifying Facility issue is separate and distinct from our proposed behind the meter exception and was properly considered by the presiding judge.

106. Vernon's request for clarification is also denied. Of course, Docket No. EL00-105 will directly resolve the TRR issues only with respect to Vernon. However, it should be apparent that this does not constrain the Commission from resolving issues of general application in the context of deciding Vernon's case.

107. Finally, the ISO's compliance filing in response to the July 2003 Order was predicated on that order's determination concerning the behind-the-meter exception to gross load allocation of the TAC. Therefore, the Commission rejects as moot the compliance filing and the protests and comments in response. The ISO will be directed to make another compliance filing upon the resolution of the behind the meter exception issue.

IV. Requests for Rehearing of the May 2003 Order

108. The May 2003 Order consolidated five issues for purposes of hearing with the Amendment No. 27 proceeding. These related to aspects of the transition charge, the allocation of costs between high voltage and low voltage facilities, the definition of the transmission revenue credit, the conversion of existing contracts, and the treatment of behind the meter load. The order went on to reject one of the remaining parts of the ISO's proposed tariff Amendment No. 49 for filing, but accepted the rest, effective June 1, 2003.

109. Requests for clarification and/or rehearing of the May 2003 Order were filed by Modesto, NCPA, PG&E, SoCal Edison, and TANC.[90]

[90] The Cities of Santa Clara and Palo Alto, California, and the M-S-R Public Power Agency jointly filed a request for rehearing incorporating by reference the arguments made by TANC.

110. Several of the issues raised in the requests for rehearing have become moot. SoCal Edison and PG&E contest the March 2003 Order to the extent it accepted the ISO's proposed definition of "PTO Service Area." However, in the Initial Decision, the judge indicated that this issue was resolved by stipulation.[91] Similarly, claims raised by PG&E concerning the proposed definition of gross load were resolved by unopposed stipulation.[92] PG&E and TANC raise arguments concerning the effect of Amendment No. 49 on the economic analysis of proposed transmission expansions. However, this issue was resolved by the judge,[93] and not subject to exceptions. The Commission dismisses these rehearing requests as moot.

111. Modesto and TANC request rehearing on issues relating to the Commission's approval of ISO's proposal to eliminate the Revenue Review Panel, which it had originally intended to review TRRs of non-jurisdictional public utility entities which become New Participating TOs. However, because we had previously determined that the Panel's decisions would be appealable to the Commission,[94] the ISO was now dispensing with the Panel altogether. The May 2003 Order approved the elimination of the Revenue Review Panel. As we explained, the Panel

> has become unnecessary since all five municipal utilities that have become Participating [TO]s have chosen to file their proposed [TRRs] with the Commission . . . We also find that it would be administratively more efficient for the Commission to directly review and determine the justness and reasonableness of the [TRRs] of new Participating [TOs].[[95]]

112. TANC and Modesto argue on rehearing that by eliminating the Revenue Review Panel, the Commission is requiring that non-jurisdictional municipal utilities file their proposed TRRs with the Commission. This course, they reason, improperly expands Commission jurisdiction over municipal utilities, from which they are statutorily exempt.

113. The Commission denies rehearing. First, because all Governmental Entities seeking to become new Participating TOs have voluntarily filed their TRRs with the Commission, the concerns of TANC and Modesto are speculative. Second, the parties

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[91] Initial Decision, 106 FERC ¶ 63,206 at P 326.

[92] *Id.* at P 338.

[93] *Id.* at P 325.

[94] *Calif. Indep. Sys. Operator Corp.*, 91 FERC ¶ 61,205 (2000)

[95] March 2003 Order, 103 FERC ¶ 61,260, at P 21.

ignore that the United States Court of Appeals for the District of Columbia has ruled that the Commission review of a municipal entity's TRR is justified to assure that the ISO's rates will be just and reasonable.[96]

114. NCPA requests rehearing of the Commission's rejection of the ISO's proposal to provide a waiver whereby the Western Area Power Administration could turn over to the ISO control of the new transmission facilities it proposes to construct to upgrade Path 15, even if it did not turn over operational control of its existing transmission facilities. NCPA faults the Commission for rejecting the concept of a transmission owner turning over control to the ISO of some, but not all, of its transmission facilities.

115. The Commission denies NCPA's request for rehearing as moot. In an order issued on November 5, 2004, we determined that a waiver of the requirement to turn over operation control of all of Western's transmission facilities to the ISO was appropriate.[97]

The Commission orders:

(A) The Initial Decision is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) The Partial Initial Decision is hereby affirmed, as discussed in the body of this order.

(C) DWR's motion to reopen the record is hereby denied, as discussed in the body of this order.

(D) The ISO's request for clarification concerning Governmental Entities is hereby granted. All other requests for rehearing and/or clarification are hereby denied, as discussed in the body of this order.

(E) The Commission hereby defers its determination on the requests for rehearing raising the gross load exception issue, as explained in the body of this order.

(F) Any motions or requests filed by the parties and not specifically referred to herein are hereby denied.

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[96] *Pacific Gas and Electric Co. v. FERC*, 306 F.3d 1112 (2003). The court, however, remanded the matter to the Commission because it was not clear the standard by which the Commission was conducting the rate review.

[97] *Calif. Indep. Sys. Operator Corp.*, 109 FERC ¶ 61,153 (2004) *reh'g pending*.

(G) The ISO's compliance filing in response to the July 2003 Order is hereby dismissed as moot.

(H) The ISO is hereby directed to make a compliance filing with respect to the matters directed in this order. The ISO must make this filing with thirty days of this order, unless there is a request for rehearing of this order, in which case the ISO must make the filing within thirty days of a final order by the Commission.

By the Commission.

(S E A L)

Linda Mitry,
Deputy Secretary.