UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, and William L. Massey.

Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company	Docket Nos. EC96-19-001, EC96-19-002, EC96-19-003, EC96-19-004, EC96-19-005, ER96-1663-001, ER96-1663-002, ER96-1663-003, ER96-1663-004, ER96-1663-005 and ER96-1663-006
Pacific Gas and Electric Company	Docket No. OA96-28-000
San Diego Gas & Electric Company	Docket No. OA96-139-000
Southern California Edison Company	Docket Nos. ER96-222-000, OA96-76-000, OA97-602-000 and OA97-604-000

ORDER CONDITIONALLY AUTHORIZING LIMITED OPERATION OF AN INDEPENDENT SYSTEM OPERATOR AND POWER EXCHANGE, CONDITIONALLY AUTHORIZING TRANSFER OF CONTROL OF FACILITIES ON AN INTERIM BASIS TO AN INDEPENDENT SYSTEM OPERATOR, GRANTING RECONSIDERATION, ADDRESSING REHEARINGS, ESTABLISHING PROCEDURES AND PROVIDING GUIDANCE

(Issued October 30, 1997)

I. Introduction

On August 15, 1997, the Trustee for the California Independent System Operator Corporation (ISO) and the California Power Exchange Corporation (PX) (collectively the ISO/PX), Southern California Edison Company (SoCal Edison), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) (collectively, the Companies) tendered several filings (August 15 Filing) to implement Phase II of the comprehensive restructuring of the California electric marketplace, and to respond to the Commission's July 30, 1997, order in Docket Nos. EC96-19-003 and ER96-1663-003. 1/

In this order, we are providing interim and conditional authorization under sections 203 and 205 of the Federal Power Act (FPA), 16 U.S.C. □□ 824b,

1/ Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, 80 FERC □ 61,128 (1997) (July 30 Order).

824d (1994), to the ISO and PX to commence their operations. We will closely monitor the operations of the ISO and PX, require further studies and reporting by the ISO and PX, and will make modifications to our authorization in the future if circumstances warrant. In addition, as a condition to such interim authorization, we will require the Chief Executive Officers of PG&E, SoCal Edison, SDG&E, the ISO and the PX each to certify to the Commission prior to the date that ISO and PX operations commence, that all of the necessary features are in place to ensure reliable grid operations when the ISO and PX commence operations, and that sufficient pre-operational testing will be performed.

We find that, with the modifications and conditions discussed herein, the ISO meets the Commission's eleven ISO principles set forth in Order No. 888. 2/ Therefore, we authorize the ISO and PX each to commence limited initial operations November 1, 1997, and conditionally grant interim section 203 authorization for the transfer of operational control of the Companies' transmission systems to the ISO.

In addition, in this order, we conditionally accept the ISO/PX plan to implement certain elements of the restructuring proposal after the commencement of ISO and PX operations; require staged features of the proposal to be initially removed from the ISO and PX Tariffs and posted on the ISO's electronic network (WEnet) and refiled under section 205 prior to implementation; direct the PX to file certain Activity Rules under FPA section 205; and conditionally grant the ISO/PX's request to delay the filing deadline for various subsidiary Agreements and to file a compliance filing after operations commence. 3/ We also address a number of requests for rehearing of our prior orders in these proceedings; accept the ISO/PX proposal to accommodate existing contracts and to phase-out over a five-year transition period existing contracts with new Participating Transmission Owners and to conform operations under existing contracts with ISO Tariff operations; and address a myriad of issues regarding the many duties and responsibilities of the ISO, utilities and Market Participants with respect to such aspects of the proposal as metering, Scheduling Coordinators, the Transmission Control Agreement and Ancillary Services.

2/ Promoting Wholesale Competition Through Open Access Non-discriminato Transmission Services by Public Utilities; Recovery of Stranded Cost Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. 21,540 (May 10, 1996), FERC Stats. & Regs. □ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. □ 31,048 (1997), reh'g pending.

3/ We are not now requiring a compliance filing due to the interim natu of our approval. Because we anticipate further tariff clarification and revisions under the Staging Proposal, we will defer the filing requirement. However, we will require that the ISO and PX Tariffs, together with all related appendices and agreements, as revised by t order, be promptly posted on the ISO's WEnet.

As discussed below, we conditionally accept with modifications and conditions the ISO/PX plan for managing congestion on the ISO Grid, including the use of Adjustment Bids to set the Usage Charge and modify the ISO/PX Overgeneration proposal. Moreover, as discussed herein, we approve several aspects of the August 15 ISO and PX proposals on an interim basis while requiring that the ISO and/or PX conduct further studies and reports. In addition, the Commission orders that these studies and reports be conducted by or under the direction of the ISO or PX monitoring staff, as appropriate.

Also in this order, we conclude that the horizontal market power of PG&E and SoCal Edison will be reduced substantially after their proposed divestiture of certain geothermal and fossil-fuel generating units and find that, pending divestiture, the Companies' proposed mitigation measures, including bid floors and authority for the ISO or PX to impose bid caps and monitoring, are initially adequate to address market power concerns raised by intervenors. In addition, we will continue to monitor and oversee the further development and evolution of the ISO and PX to ensure that potential market power problems are identified and that appropriate mitigation measures are undertaken. Finally, as discussed below, we will accept on an interim basis, and with modifications, the pro forma contracts for compensating Must-Run generating units.

In conjunction with these findings, the Commission will grant the ISO and PX request to file a compliance filing incorporating the modifications to the proposals detailed in this order after the service operation date. In the future, the Commission will order separate comprehensive compliance filings for the ISO and PX. However, the ISO and PX each must fulfill their commitment to file outstanding agreements, protocols, and other related documents proposed to go into effect at the commencement of operations no later than November 1, 1997.

In addition, there are a number of filings that the ISO/PX has indicated that will be filed both in the near future and after ISO and PX operations commence under the staging plans. The Commission does not in this order purport to address any of these yet unfiled documents. To the extent that issues are raised with respect to those filings, they will be addressed in subsequent orders.

The extent of our authorization is subject to several important qualifications. First, this order addresses numerous issues raised by the parties with respect to the filings before us. It is simply not practical (nor manageable) to fully describe all of the comments and proposals that have been put forth. To the extent that the order addresses a proposal put forth by many parties, the Commission s response is applicable to all parties that proposed the modification. On the other hand, to the extent that the order does not address a proposed modification or a related nuance of an issue addressed in the order that is raised by a party, that proposal is deemed denied. 4/

4/ However, any request for rehearing in these proceedings that we do n
(continued...)

Second, Appendix I, Part I to the August 15 Filing contains a description of more than three hundred modifications or clarifications of the proposal that the ISO/PX has categorized as resolving outstanding issues with

the parties. 5/ To the extent that the parties have not raised objections to these modifications, the Commission will consider these issues as resolved between the ISO, PX and the stakeholders. Furthermore, unless specifically addressed in this order, the Commission will consider prior arguments addressing these issues as moot and accept these modifications to the proposal.

A. Background

Phase I Filing

In Phase I of these proceedings, the Companies filed their Phase I proposals to restructure the California electric marketplace, consistent with decisions of the Public Utilities Commission of the State of California (California Commission) and the California Legislature. 6/

In the Phase I filings, the Companies proposed to establish the California ISO and PX as separate entities, to authorize sales of energy at market-based rates, and to establish the rates, terms and conditions for service under the restructured framework. These filings consisted of: (1) the Companies request for a declaratory order in Docket No. EL96-48-000 determining the jurisdictional split between transmission and local distribution; (2) the Companies request to sell energy at market-based rates in Docket No. ER96-1663-000; and (3) the Companies request to transfer operational control of facilities to an independent system operator in Docket No. EC96-19-000.

The Commission convened technical conferences on the Phase I filings on August 1, 1996 and September 12 and 13, 1996. The Commission granted the petition for a declaratory order, in part, in its October 30, 1996 order. 7/ Among other things, the Commission's orders dated November 26, 1996 and December 18, 1996, in Docket Nos. EC96-19-000 and ER96-1663-000, authorized

4/ (...continued)
address herein is not deemed denied, and will be addressed at a late date.

5/ August 15 Filing, Appendix I.

6/ See California Commission Decision D.95-12-063 (Dec. 20, 1995), modi by, D.96-01-009 (Jan. 10, 1996) and D.96-03-22, 166 P.U.R. 4th 1 (California Commission Decision); Assembly Bill 1890, signed by Gove Wilson on September 23, 1996 (Restructuring Legislation).

7/ Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, 77 FERC □ 61,077 (1996) (October Order).

the establishment of the ISO and PX, convened a technical conference on market power issues on January 17, 1997, and directed the ISO and PX to file Phase II of the restructuring proposal no later than March 31, 1997. 8/

Phase II Filing

The ISO/PX and the Companies tendered several filings to implement their Phase II proposal on March 31, 1997. 9/ The Phase II submissions in Docket Nos. EC96-19-003 and ER96-1663-003 included, inter alia, the ISO/PX's filings, consisting of the ISO organizational and governance documents, the ISO's Operating Agreement and Tariff, the Transmission Control Agreement and other materials and explanations required by the Commission as a condition to the transfer of operational control of transmission facilities in the State of California from the Companies to the ISO, the PX's organizational and governance documents, the PX's Operating Agreement and Tariff and other materials and explanations required by the Commission.

The March 31, 1997 filings in Docket Nos. EC96-19-003 and ER96-1663-003 also included a Pro Forma Transmission Owner s Tariff jointly tendered by the Companies. 10/ The Companies stated that the Transmission Owner s Tariff, in conjunction with the tariff and agreements submitted by the ISO/PX, contains the rate methodology, and certain terms and conditions related to transmission service provided over the Companies' facilities over which the ISO will have operational control. The Companies also submitted with the filing their joint response to questions raised by the Commission in its Phase I orders in this proceeding. Also on March 31, 1997, the Companies filed individual statements addressing mitigation of market power and treatment of existing contracts.

8/ Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, 77 FERC □ 61,204 (1996) (November 26 Order); Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, 77 FERC □ 61,265 (1996) (December 18 Order) (collectively referred to as the Phase I Orders).

9/ The ISO/PX Trustee made these filings, rather than the ISO and PX Governing Boards, which were not yet in existence. The ISO and PX Governing Boards subsequently were approved by the Oversight Committ met, and approved the Trustee's filing, with some modifications. Th modifications were submitted with the May 20, 1997 response to the Commission Staff's April 29, 1997 Request for Additional Information

10/ Concurrently, the Companies filed in Docket Nos. ER97-2355, ER97-235 and ER97-2364, pursuant to section 205 of the FPA, the cost support underlying the utility-specific rates to be charged for transmission service by the ISO. The Companies request that the Commission addre the utility specific rates in the Companies respective section 205 tariff proceedings. The Commission will address these filings in a separate order.

The Phase I and Phase II proposals were developed under the auspices of the WEPEX Steering Committee, 11/ which directed an ongoing process emphasizing wide stakeholder participation in the evolution of the restructuring proposals. Even after the Phase II proposals were filed, the ISO/PX indicated that it continued to negotiate with the parties to address numerous concerns and further refine the proposals. In addition, due to time constraints, the ISO/PX determined that implementation of some restructuring features must be delayed. As a result of these developments, the Commission determined that the Phase II filing no longer reflected the proposal that the ISO/PX proposed to implement effective January 1, 1998. Accordingly, the July 30 Order directed the ISO and PX to file restated Tariffs, Agreements and

Appendices, reflecting the operations of the ISO and PX that they propose to become effective on January 1, 1998, details of the ISO and PX plans to stage implementation, a catalogue of issues (listing resolved issues proposed for January 1, 1998 implementation, resolved issues proposed for future implementation, and issues remaining in contention), and other outstanding information.

August 15 Filing

The August 15 Filing was submitted in response to the Commission s July 30 Order. Specifically, the ISO/PX August 15 Filing includes: 12/

Appendix I	Catalogue of Issues
Appendix II	Staging Plan
Appendix III	Responses to Requests for Additional Information Made by the Commission Staff on July 18, 1997
Appendix IV	Amended Bylaws (Code of Conduct Portions) and Acronym List
Appendices V and VIII	Restated and Amended ISO Tariff and Operating Agreement
Appendices Va and VIIIa	Restated and Amended Master Must-Run Agreement
Appendices VI and IX	Transmission Control Agreement
Appendices VII and X	Restated and Amended PX Operating Agreement and Tariff

In addition, on August 15, 1997 the Companies filed their revised pro forma Transmission Owner Tariff, and individual responses to certain of the

11/ The Companies established a formal structure, the Western Power Exch (WEPEX), to implement the restructuring objectives.

12/ The ISO/PX did not refile several pro forma agreements and certain o operating agreements which were not completed in time for filing by August 15, 1997. In addition, the ISO/PX did not refile certain unamended Appendices. As discussed below, the ISO/PX requests waive and/or reconsideration of the August 15, 1997 filing deadline for th documents. August 15 Filing at 7-9.

Requests for Additional Information made by the Commission Staff on July 18, 1997. 13/

On October 17, 1997, the ISO filed in Docket No. ER98-211-000 its proposed Grid Management Charge, and the PX filed in Docket No. ER98-210-000 its proposed PX Administrative Charge. These filings will be addressed in a separate order.

B. Preliminary Matters

ISO/PX Trustee's Combined Filing

The Commission notes that the ISO/PX submitted the August 15 Filing jointly. As noted in our November 26 Order, the ISO and PX are separate

entities. 14/ Accordingly, the Commission directs the ISO and PX to henceforth make separate filings with respect to their separately administered Tariffs and underlying agreements.

In addition, some parties have pointed out that the August 15 Filing was tendered by the ISO/PX Trustee rather than by the ISO and PX themselves. The Commission is aware that the ISO and PX were under extremely difficult time constraints in preparing the August 15 Filing. Since that filing was made, the ISO and PX Governing Boards have had ample opportunity to inform the Commission as to any elements of the filing that they do not endorse. Under these circumstances, the Commission will presume that the ISO/PX Trustee had full authority to make the August 15 Filing on behalf of the ISO and PX Governing Boards, and that these Boards endorse the filing. The Commission expects that where the ISO and PX Governing Boards do not agree with any aspect of any submission made on their behalf, they will promptly inform the Commission.

Conventions Utilized in the Order - Capitalized Terminology, Comment References

The Commission notes that virtually all of the parties to these proceedings have utilized terms as defined in the Master Definitions Supplements, set forth in Appendix A of the ISO Tariff and Appendix D of the PX Tariff, filed on August 15, 1997. The Commission will also use these terms in this order. 15/ Accordingly, capitalized terms used in this order reflect

13/ Also, PG&E filed a supplemental Affidavit of Dr. Joe D. Pace address the recent acquisitions by PG&E Corporation and two of its subsidiar

14/ November 26 Order, 77 FERC at 61,809-810.

15/ We do not by using these terms specifically endorse the definitions contained in the ISO and PX Master Definitions Supplements for purpo other than this order.

terms that conform to the terms contained in the ISO and PX Master Definitions Supplements, as set forth in Appendix A.

Comments described under the headings "Contested Issues Identified by the ISO/PX" were all submitted in response to the March 31 Filings on or about June 6, 1997. Comments described under the heading September 2, 1997 Comments were all submitted in response to the August 15 Filing on or about September 2, 1997.

Interventions and Comments

Intervenors in Docket Nos. ER96-1663 and EC96-19 continue to have party status in the Phase II proceeding. 16/ Since our July 30 Order, motions to intervene out of time were filed by the City of Redondo Beach, California (Redondo Beach), National Association of Energy Service Companies (NAESCO), and Southern Energy Trading and Marketing.

On September 26, 1997, SoCal Edison filed an Answer opposing Redondo

Beach s late intervention, claiming that Redondo Beach failed to establish good cause for its late filing. SoCal Edison states that Redondo Beach has been aware since the December 18 Order that the ISO would make a determination of must-run facilities, and that Redondo Beach fails to explain why it has taken since June 1997, for Redondo Beach to determine the identity of relevant jurisdictional bodies, as claimed in its motion. Finally, SoCal Edison asserts that in its communications with Redondo Beach, it has consistently maintained that its Redondo Beach generating facility would be a must-run facility, unless and until certain transmission upgrades are installed. 17/

We find good cause to grant the untimely motions to intervene. However, given the lateness of their requests to intervene at this stage of the proceeding, Southern Energy and Marketing, NAESCO, and Redondo Beach must accept the existing record as they find it. Considering the wide-ranging implications of the California restructuring, it is appropriate to allow as many participants as possible to have input into the process. In addition, we find no undue delay on the part of Redondo Beach. The process by which the ISO will identify must-run facilities is not so easily ascertained, and with jurisdiction divided among various regulatory bodies, Redondo Beach s confusion in determining its need to intervene in this proceeding is understandable. Indeed, notwithstanding SoCal Edison s assertions that the ISO has identified the Redondo Beach facility as a must-run facility, 18/ no filing to that effect has been made at the Commission. Moreover, because Redondo Beach, NAESCO, and Southern Energy and Marketing are required to

16/ See November 26 Order, Appendices A-D; December 18 Order, Appendix A and July 30 Order, Appendices A, B and C.

17/ SoCal Edison September 26 Answer at 3.

18/ SoCal Edison September 26 Answer at 1-2.

accept the record as it stands, no prejudice would result from their obtaining party status at this time.

Comments in response to the March 31 Filings were due on June 6, 1997. The ISO and PX, the Companies, and several municipal utilities filed Reply Comments on June 23, 1996. Notice of the ISO/PX Reply Comments was published in the Federal Register, 19/ with Comments addressing the ISO/PX Reply Comments due on July 8, 1997, and Comments addressing the Companies' June 23 submissions due on July 23, 1997. Comments on the August 15 Filing were due on September 2, 1997.

On July 3, 1997, the City of Vernon (Vernon) filed a motion to strike portions of SoCal Edison's June 23 Reply Comments, 20/ contending that the response to Vernon contained in those Comments is not permitted by the Commission's rules because it was not filed until six weeks after Vernon's initial protest. In addition, Vernon contends that SoCal Edison's Reply Comments raise new matters that Vernon had not had an opportunity to address. On June 23, 1997, SoCal Edison filed an answer to Vernon's Motion To Strike, contending that Vernon did not provide a legitimate basis for striking SoCal Edison's comments. SoCal Edison states that its Reply Comments directly respond to the positions Vernon advanced in its protest and that its Reply Comments were procedurally proper because Vernon alone filed a protest twenty five days before interventions and other protests were due and filed. 21/

On July 8, 1997, Enron Power Marketing, Inc. (EPMI) filed a motion to file a reply to the June 23, 1997 reply comments of several municipal utilities regarding the treatment of existing contracts. EPMI contends that it had not previously had an opportunity to address these comments. TANC filed an Answer opposing EPMI's motion, contending that EPMI does not raise new matters that could not have been addressed previously. 22/

On August 8, 1997, SoCal Edison filed a Motion to Strike several pleadings filed by parties on July 23 1997, contending that the comments in question did not fall within the scope of the Commission's June 26, 1997, Notice of Filing. 23/ In addition, SoCal Edison contends that these parties

19/ 62 Fed. Reg. 35,800 (1997).

20/ Vernon requests that the Commission strike from SoCal Edison's June Reply Comments the discussion on pages 37-43 under the heading "The Commission Should Reject Vernon's Attempt to Force Other Transmissio Customers to Subsidize Vernon." Vernon July 3, 1997 Motion to Strik 3.

21/ SoCal Edison Answer to Vernon's Motion to Strike at 7.

22/ TANC July 23, 1997 Answer in Opposition to the Motion of Enron Power Marketing, Inc. for Leave to File Reply.

23/ SoCal Edison moves to strike the entire Comments of Cogenerators of

(continued...)

do not raise any facts or arguments that could not have been presented previously. In the alternative, SoCal Edison requests leave to file an additional answer to these comments.

The ISO/PX, the Companies, Western, Turlock, SMUD, TANC, Metropolitan, and LADWP filed motions to file answers to the Comments filed in these proceedings on September 2, 1997. These parties recognize that the Commission's July 30 Order did not provide for additional comments and the Commission s rules normally do not permit answers to answers. 24/ However, they contend that their additional comments will assist the Commission in creating a better record, assist it in considering the issues and the parties' positions, and correct factual misstatements. 25/ In addition, Metropolitan and TANC state that the September 2, 1997 submissions by the Companies, the California Commission, and PG&E contain new or additional arguments or proposals. 26/

Also on September 16, 1997, the ISO/PX filed a motion to respond to certain requests for rehearing filed August 29, 1997, contending that the responses will assist the Commission in its consideration of these issues, will allow the Commission to assemble a more complete record and may resolve some the issues that the Commission would otherwise have to address.

On September 30, 1997, TANC filed a limited response to the ISO/PX September 16 Comments, and on October 2, 1997, Turlock filed a limited response to PG&E's response to one of the Staff questions in view of Turlock's informal discussions with PG&E.

We find good cause to grant waiver of our regulations to allow the additional comments in this instance. 27/ As the parties note, the August 15 Filing and the September 2, 1997 Comments included new proposals that had not previously been addressed. Similarly, TANC s September 30 Comments address a new procedure suggested in the ISO/PX September 16 Comments. Under these

23/ (...continued)
Southern California and the Energy Producers and Users Coalition to June 23, 1997 Utilities Submittals; most of the comments of Californ Cogeneration Council on PG&E's Answer and SoCal Edison's Response; a the entire EPMI Reply to Answer in comments on Market Power Filing.

24/ 18 C.F.R. □ 385.213(2) (1997).

25/ Western September 16 Comments at 3; Turlock September 16 Comments at and SMUD September 16 Comments at 1-2.

26/ Metropolitan September 16 Comments at 2-3; TANC September 16 Comment 2.

27/ We do not here address an additional Motion of the City of Vernon fo Rejection of SoCal Edison's July 23, 1997 Response to Comments Recei July 23, 1997, in Docket No. ER97-2355. As noted above, we will add pleadings in that docket in a separate order.

circumstances, it is appropriate that we afford all participants an opportunity to keep us informed. As noted in our November 26, 1996 order (77 FERC at 61,808):

> While our regulations generally prohibit answers to protests, we have adopted in this proceeding procedures to afford parties ample opportunity to express their positions and respond to other parties' positions in their pleadings. We believe that permitting the Companies' answer is consistent with that approach. Moreover, the Companies' answer has assisted us in understanding the issues raised.

Procedural Proposals

1. Request for Waiver of the August 15 Filing Deadline

The ISO/PX requests waiver or reconsideration of the August 15 Filing deadline for several portions of the filing that the ISO and PX intend to implement by January 1, 1998. 28/ These include:

(1) Pro Forma UDC Operating Agreements, Meter Service Agreements, and Generator Operating Agreements, which the ISO decided to defer until the final design of the ISO Tariff;

(2) Operating Agreements with adjoining control area operators, which were not submitted because they are bilateral agreements which must be individually negotiated and the necessary ISO contract administration staff has just been hired;

(3) Reliability Must-Run Cost Recovery Agreements, which were not submitted because the schedules for unit operations are still being negotiated; 29/ and

(4) Service Agreements with Existing Black Start Providers, which have not yet been negotiated.

Several parties agree to the request for waiver, so long as the necessary documents are filed no later than November 1, 1997. However, they object to a waiver of a filing requirement for these documents, stating that they must be filed and reviewed by the Commission under FPA section 205. For example, Southern Cities/Azusa and Banning are particularly troubled by the

28/ August 15 Filing, Transmittal Letter at 7-9.

29/ See the ISO/PX's August 22, 1997, corrections to the August 15 Filin 1-2.

failure to file a draft UDC Agreement, and strongly oppose any limitation on the scope of the Commission s review of that Agreement. 30/

Commission Response

We will grant the ISO/PX request for reconsideration of the August 15, 1997 filing deadline for these pro forma agreements. 31/ According to the ISO/PX, the final design of the ISO Tariff has been completed, which will allow the development of the UDC Operating Agreements, Meter Service Agreements and Generator Operating Agreements. In addition, the contract administration staff required for negotiating the remaining agreements has only recently been hired. As noted in their request, the actual agreements, which will go into effect no earlier than January 1, 1998, are required to be filed on sixty days' notice. With the progress to date on the development of the agreements and the recent staffing, we expect the ISO and the PX to make every effort to execute and timely file the necessary agreements. As for various Parties' concerns over section 205 review, we emphasize that this order does not approve those parts of the restructuring proposal that have not yet been filed with the Commission. While we will preliminarily address discrete issues related to these agreements, the actual agreements must be filed and will be subject to further section 205 review.

2. Standard for Subsequent Filings

In the July 30 Order, the Commission accepted the ISO/PX proposal to submit protocols and procedures for the ISO and PX with the Commission for informational purposes no later than November 1, 1997. Adhering to its existing "rule of reason" policy, the Commission did not require a formal section 205 filing of ISO and PX documents at that time because, while implicating our jurisdiction, they mostly involve general operating procedures.

SoCal Edison seeks rehearing of this determination, contending that

protocols that involve classifications, practices and regulations affecting rates and charges should be filed under FPA section 205 and found by the Commission to be just and reasonable. In its September 2, 1997 comments, SoCal Edison argues that many key bidding and pricing issues in the PX have been explicitly left for resolution in yet-to-be submitted protocols, making analysis of the effects of the revised tariffs difficult because the data are incomplete. SoCal Edison contends that this problem underscores the basis for its rehearing request regarding the Commission s determination as to what may

30/ Santa Clara and Palo Alto at 29; Redding at 33; Southern Cities/Azus and Banning at 41.

31/ Similarly, we grant reconsideration for the filing of unamended Appendices. We will require that these documents not be refiled unt the compliance filing of the underlying agreements as discussed late this order.

be filed for informational purposes and what documents must be filed under FPA section 205. 32/

Similarly, CCEM claims that core terms and conditions of transmission service are not included in the ISO Tariff, but rather have been "swept under the 'protocols' rug." CCEM requests that the Commission require the ISO to file all relevant terms and conditions for its review, under the Commission's rule of reason policy. 33/ Numerous other instances of incomplete details and lack of critical protocols are cited in many of the comments. 34/

As noted above, several parties agree to the delay in filing certain agreements and Protocols, so long as they ultimately are filed and reviewed by the Commission under FPA section 205.

ISO/PX September 16 Response

In their September 16, 1997 response, the ISO/PX contends that the PX will establish a commodity market in a restructured and deregulated environment, monitor market power, and establish procedures to mitigate market power, and that these functions require the PX be able to respond quickly and without regulatory delay. 35/ For example, the ISO/PX contends that the PX may need to revise the Auction Activity Rules quickly to respond to an entity that is gaming the bidding rules.

The ISO/PX further contends that the Commission did not exempt the PX Protocols or any rates from its jurisdiction, that the broadly constituted Governing Boards help ensure that any changes to the Protocols will be appropriate, 36/ and that in any event the Auction Activity Rules mostly involve "operating procedures" as described in the Commission's July 30 Order. 37/ The ISO/PX disagrees that the Commission must require section 205 filing of Protocols that the Commission has not yet had a chance to review, and commit to seek such authorization as to any provisions that "are plainly

32/ SoCal Edison does not request that all protocols be filed; it stated intention to resolve that question with the ISO and PX on an informa

basis. SoCal Edison at 2-3.

33/ CCEM at 8-9.

34/ See, e.g., NCPA at 23-27.

35/ ISO/PX September 16 Response at 10-11.

36/ In fact, the ISO/PX states that drafts of the proposed Protocols wil circulated to Stakeholders for their review prior to filing on Novem 1, 1997. (Id. at 14.)

37/ Id. at 12.

subject to section 205 authorization." 38/ Finally, the ISO/PX states that the Commission should defer consideration of any changes beyond those previously ordered by the Commission or agreed to by the ISO/PX, in view of the ongoing stakeholder process that it states will continue. The ISO/PX states that it will make future filings pursuant to FPA section 205 to incorporate revisions that the ISO/PX determines to be necessary and desirable. 39/

TANC requests that the Commission reject the ISO/PX proposal to defer consideration of any changes not already ordered or agreed to by the participants, arguing that there are many fundamental issues that the Commission must address prior to commencement of ISO and PX operations, pursuant to its FPA authority. 40/

Commission Response:

We find the filing procedure outlined by the ISO/PX in its September 16, 1997 Motion to be consistent with our July 30, 1997 Order. Under our "rule of reason," the ISO and the PX will in the first instance identify the protocols that should be filed under section 205 and not simply for informational purposes. We understand that the ISO and the PX are also distributing drafts of the protocols for stakeholder review prior to the filing. In reviewing the applications, which are to be made by November 1, 1997, the Commission as well as interested parties can evaluate and determine which protocols will require section 205 review. Similarly, the ISO must also file certain operational procedures under FPA section 205.

However, our acceptance of the ISO/PX proposed filing procedure is subject to the following limitations. First, as discussed in more detail below, the PX must file its proposed Activity Rules under FPA section 205, inasmuch as these rules will affect the determination of prices under the PX.

Second, we agree with TANC that we should reject the ISO/PX proposal to simply defer consideration of the many tariff revisions that have been advanced by the parties and that the ISO and PX have not yet adopted. The ISO/PX would have us allow the August 15 filing to go into effect on January 1, 1998, and to govern the operations of the ISO and the PX without prior Commission review. That is not acceptable. Many parties have raised valid arguments that certain modifications to various aspects the proposal are necessary and must be implemented at the time that ISO and PX operations commence, in order to assure that the ISO and PX proposals are just and reasonable. To the extent that the ISO and PX reach resolutions with

stakeholders during their ongoing and future negotiations that require a

38/ Id. at 13.

39/ Id. at 4-5.

40/ TANC September 30 Comments at 4-5.

change to their tariffs and other agreements and protocols, they must file such changes with the Commission.

3. Staging Plan

The August 15 Filing contains a staging plan, as required in the Commission's July 30 Order. The ISO/PX indicates that the proposal to stage commencement of operations may be beneficial and will allow participants to gain experience with the more sophisticated features of the market. The ISO/PX lists eight ISO elements that will be staged: 41/

1. Permanent historical information storage system to be implemented by April 1, 1998 (Temporary storage in the interim);

2. The price of Energy delivered from Spinning, Non-Spinning and Replacement Reserve resources will be calculated every five minutes beginning July 1, 1998. (Energy delivered from these resources will be priced at the Hourly Ex Post Price initially.)

3. Transmission Losses calculated using Generator Meter Multipliers (GMMs) will be based on ex-post numbers by July 1, 1998. (GMMs will be based on last available forecast in lieu of ex-post numbers initially.)

4. At a yet-to-be determined date, the ISO will determine the applicable Usage Charge for Ancillary Services bid evaluation in accordance with ISO protocols. (Initially, the ISO will use an estimated Usage Charge in the bid evaluation for Ancillary Services).

5. Intra-zonal congestion will be determined using AC Optimal Power Flow methods by January 1, 1999. (Initially, intra-zonal congestion will be determined by standard power flow models.)

6. The ISO will use AC Optimal Power Flow methods to assess transmission capability, Voltage Collapse Analysis, Available Transfer Capability and Transient Stability Analysis by January 1, 1999. (Initially, the ISO will use current methods.)

7. Until January 1, 2000, the ISO Power Management System, which monitors and controls the ISO Controlled Grid and power plants,

41/ August 15 Filing, Appendix II, at 2-3. In addition, in response to July 30 Order, the ISO/PX clarifies that there will be an Hour-Ahead

market conducted by the ISO for Ancillary Services and Congestion Management on January 1, 1998, that no revisions to Energy Schedules during the Hour-Ahead scheduling process have been contemplated, and that there will be a Day-Ahead Market for Ancillary Services on Janu 1, 1998.

will work through the existing control centers of California's four largest utilities.

8. The ISO will increase the communication system capacity to serve market participants as the number of participants increases. (Initially it will serve 2,000 participants.)

The ISO/PX lists two Phases of PX staging. 42/ Phase 1 of PX implementation will consist of three Stages:

1. Initially, there will be a Day-Ahead Market in which there is only one bid submitted by Market Participants;

2. By March 28, 1998, the PX will implement an Hour-Ahead Market; and

3. By June 27, 1998, iterative bidding will commence.

Phase 2 of PX implementation will take place in the second half of 1998, and will consist of the following elements:

1. the PX will self provide Ancillary Services at prices determined in its own Ancillary Service auction; 43/

2. PX participants will be allowed to self-provide Ancillary Services;

3. The PX will provide for purchase of Interruptible Import Energy in the PX market;

4. Hour-Ahead Ancillary Services bidding will be permitted;

5. The PX will consider modifying its schedule to participate in the iterative bid of the ISO's Congestion Management market; and

6. The maximum number of bidders will increase from 500 to 2,000.

The California Commission conditionally supports the proposed staging plan, if the staging occurs on schedule and other recommendations regarding the ISO and PX structure and operations are adopted. In addition, the California Commission recommends that the Commission conduct a review at the end of 1998 as to whether the ISO and PX have met their staging implementation schedules. The California Commission states that implementation of the staged

42/ August 15 Filing, Appendix II, at 4-5. In addition, in response to July 30 Order, the ISO/PX clarifies that Market Participants in the bilateral market that use a non-PX Scheduling Coordinator will have ability to sell energy into the PX on January 1, 1998.

43/ As clarified below, unless they receive Commission approval to price Ancillary services at market based rates, public utilities' revenues

will be capped at the cost-based rate.

elements is critical to mitigation of market power and development of a competitive, efficient electricity market. 44/ Similarly, SMUD states that the Staging Plan should be updated and should contain firm dates for implementation of the staged elements. SMUD recommends that an automatic mitigation measure, such as cost-based rate caps, be imposed in the event the ISO and PX fail to meet their implementation schedule. Finally, SMUD recommends that the Commission require the ISO and PX to make periodic informational filings to report on the status of operations. 45/

Commission Response

As the California Commission points out, "the 'ideal' solutions to outstanding issues may not be resolved by January 1, 1998, and . . . much will be learned during the initial operation of these new market structures that may, in fact, help to inform the best resolution of outstanding issues." 46/ We agree that staging implementation of the California Restructuring is necessary to ensure that start-up of operations can proceed on schedule. However, many of the elements of the staging plan are essential to the development of a well-structured market. Accordingly, we accept the proposed staging plan subject to the condition that the ISO and PX each provide quarterly status reports, as outlined below.

As the ISO/PX has acknowledged, the start-up of ISO and PX operations is an extremely complicated endeavor and staging elements of the proposal has become a procedural necessity given the timeframes adopted in the California Restructuring. In view of these circumstances, it is critical that the Commission and all participants remain clearly informed regarding the progress toward implementation. Accordingly, we agree with SMUD's suggestion and will require the ISO and PX each to file with the Commission quarterly status reports regarding the status of the restructuring implementation, with particular emphasis on any significant changes in operations or timing that are anticipated, and we will respond as necessary. The Commission clarifies that these status reports would be filed to inform the Commission and the parties; we do not intend to notice these reports for public comments. With these conditions, we see no need to conduct a formal review of the staging plan at this time.

We also decline at this time to establish sanctions in the event the ISO or PX fail to meet the implementation schedule. SMUD's proposal is overly broad and would deny the benefits of market-based operations to the participants. The staging plan has many elements that do not address just market power concerns. Accordingly, we will consider the imposition of any necessary potential measures or sanctions if and when the need arises.

44/ California Commission at 3-11.

45/ SMUD at 6-7.

46/ California Commission September 2, 1997 Comments at 4.

We note that the ISO and PX have included some provisions in their tariffs that are no longer proposed to become effective when ISO and PX operations commence. For example, PX Tariff section 3.1 provides for an Hour-Ahead Energy Market. However, as noted above, the Staging Plan would defer operation of the Hour-Ahead Energy Market until March 28, 1998. As we stated in the July 30 Order, the Tariff must contain only those elements of the proposal that the ISO or PX intend to become effective when their respective operations commence. 47/ Accordingly, the ISO and PX are directed to delete from their Tariffs and related agreements posted on the ISO WEnet all provisions that are not intended to be effective when ISO and PX operations commence. Moreover, the ISO and PX are each directed to file under section 205, at least sixty days prior to the proposed effective dates, provisions for which implementation has been staged.

4. Mid-course Review

The California Commission recommends a review no later than three years after start-up (sooner if problems develop), as a specific proceeding to assess operations and results of monitoring, and to make necessary corrections.

Commission Response

In the July 30 Order, the Commission agreed that a review of the operations of the ISO and PX is appropriate after a period of some experience, but determined that it was too soon to decide the details of such a review process until after we had completed our review of the August 15 Filing. Therefore, we deferred our determination of the appropriate time period and scope of such review.

The Commission believes that it will be necessary to conduct a comprehensive review, as the California Commission suggests. At this juncture, the Commission is inclined to agree with the California Commission that a comprehensive review should be conducted after the first three years of operations. However, based on the reports and studies filed by the ISO, PX, or the Companies, or additional information filed with us by the parties, we may in the future decide to conduct this review at a different time.

We consider careful and ongoing monitoring of the California Restructuring to be an important part of our determination to grant interim authorization at this time. Accordingly, we note that the ISO/PX has proposed, and we are accepting in this order, an interim review of the governance proposal after three years. In addition, we are in this order requiring: quarterly status reports regarding the implementation of the staging plan; a series of studies and experiments regarding the implementation and functioning of the PX Auction; a market power review to be filed at end of the transition period (60 days prior to the expiration of the Restructuring

47/ July 30 Order, 80 FERC at 61,418-19.

Legislation rate freeze); and studies regarding congestion zones and losses. We will carefully review these filings and issue additional orders and conditions or institute additional procedures, if they are needed. Of course, any entity has the right to file a complaint with the Commission to the extent that they are experiencing problems with the implementation of restructuring.

5. Rehearing of the July 30 Order and Renewed Requests For Hearings

Several parties request rehearing of the Commission's July 30 Order, claiming that the Commission erred in failing to convene formal hearings, paper hearings, or technical conferences. TANC, Metropolitan, M-S-R Public Power Agency, and the Cities of Redding, Santa Clara and Palo Alto, California argue that the numerous comments have identified unjust, unreasonable and unduly discriminatory provisions, and that, to the extent not summarily resolved, the Commission should have set these matters for hearing. They claim that hearings will not delay the commencement of operations if, as they propose, the Commission conducts these hearings after the commencement of ISO and PX operations in 1998. 48/

These parties argue that the Commission erred in denying hearings prior to submission of the final proposed arrangements in response to the July 30 Order, without prejudice to further requests for hearings with respect to the August 15 filings. Second, they argue that the Commission's denial of requests for hearings prior to receiving the August 15 Filing is inconsistent with a determination that there are no issues of material fact. Third, they argue that the Commission erred in denying hearings with respect to completed portions of the filing that they allege raise material issues of fact. 49/

Turlock argues that the Commission erred in not granting its request for at least a paper hearing on the ISO Tariff, with respect to issues such as the proper method of cost recovery before transmission expansion facilities are constructed, consistent with FPA section 211.

SMUD argues that the Commission erred in failing to grant its request for a technical conference or other procedures, where it had showed the existence of disputed material issues of fact. 50/ SMUD contends that the Commission's ruling was inconsistent with precedent and its own rules, and states that technical conferences and Settlement Judges will assist the

48/ August 29, 1997 Requests for Rehearing of TANC at 7-9; Metropolitan 7-9; M-S-R, Cities of Santa Clara, Redding, and Palo Alto at 7-8; an Modesto at 7-9.

49/ August 29, 1997 Requests for Rehearing of TANC at 9-11; Metropolitan 9-11; M-S-R, Cities of Santa Clara, Redding, and Palo Alto at 9-11 a Modesto at 9-11.

50/ August 29, 1997 Request for Rehearing of SMUD at 3-7.

Commission in gathering the evidence necessary to reach reasoned conclusions supported by substantial evidence.

In addition, in their September 2 Comments, a number of parties request that formal hearings be conducted after the commencement of ISO operations, with prospective application of any Commission determination. These parties recommend that the Commission: (1) suspend the August 15 Filing for a nominal period and modify those filings as appropriate to remedy the shortcomings in the documents that the Commission identifies based on the written submittals of the parties; (2) allow the ISO and PX to commence operations, subject to refund, on January 1, 1998; and (3) conduct formal hearings on the disputed issues raised in the filings during 1998. At the conclusion of the process, the Commission could then issue its supplemental order modifying the ISO/PX filings, on a prospective basis, as appropriate. 51/ For example, Metropolitan and Modesto state that many issues remain for resolution, as demonstrated by the numerous comments and that the resolution of many of those issues will turn on the correctness of factual allegations set forth in the comments and the factual responses by the ISO and PX. 52/

In addition, SoCal Gas renews its request for formal hearings regarding the access fee.

Request for Expedited Procedures

TANC requests that the Commission nominally suspend the August 15 Filing for one day, and to order expedited hearings on the remaining issues while allowing the Compliance filing, as modified by the Commission in its response to the parties' September 2, 1997 comments and protests, to become effective on January 1, 1998, subject to further orders of the Commission once hearings and other procedures have been completed. 53/ TANC suggests expedited procedures such as the use of Settlement Judges, settlement procedures and limited paper hearings and proposes that, at the conclusion of these procedures, the Commission require a further compliance filing consistent with the Commission's findings. TANC argues that its proposed procedures would

51/ Modesto September 2 Comments at 62; Metropolitan September 2 Comment 85. See also, M-S-R September 2 Comments at 25-27; Redding Septembe Comments at 34-36; Santa Clara and Palo Alto September 2 Comments at 32.

52/ Modesto September 2 Comments at 62; Metropolitan September 2 Comment 85.

53/ TANC September 2, 1997 Comments at 187-188. TANC proposes to fold i the proposed expedited procedures the additional filings of agreemen and other documents that the ISO/PX will be making to complete the filing prior to the commencement of operations.

mitigate procedural deficiencies which it perceives and would allow the development an adequate evidentiary record. 54/

Commission Response

The Commission denies the requests for rehearing of our July 30 ruling that no hearings are required. As the parties recognize, in that order, the Commission found that the March 31 filing no longer represented the proposal that the ISO and PX would have us place into effect when the ISO and PX operations commence, and we required a revised filing to be submitted on August 15, 1997. Therefore, convening formal hearings on the now-moot March 31 filing would be inappropriate, and convening hearings on a yet-to-be-filed proposal would be premature. Moreover, contrary to assertions by SMUD and TANC, the requested Settlement Judge procedures would not provide an evidentiary record, since settlement discussions are by their very nature an off-the-record process. As we noted in our July 30 Order, it was unnecessary to prescribe additional settlement procedures where the ongoing stakeholder process in California served that purpose.

As noted above, several of the parties requesting rehearing request that the Commission establish formal hearing procedures to take place after ISO and PX operations commence, with prospective application of the ultimate Commission determination. These parties request hearings to address numerous alleged issues of fact that they claim are raised by the filings. We will deny these requests. Based on our examination of the alleged factual issues raised by these parties, we conclude that these issues fall into one or more of the following categories: policy issues, issues that are resolved by determinations or additional requirements for studies and reports contained in this order, issues that are moot by virtue of modifications to the proposal submitted by the ISO and PX, issues that are to be raised and addressed in other proceedings before the Commission, and issues that have been raised prematurely because operational experience is required before the issues may or may not arise. Accordingly, we do not find that there are material issues of fact that warrant formal hearing procedures as requested by these parties. 55/

For similar reasons, we deny TANC's request for a one day suspension and expedited procedures on the remaining issues while allowing the Compliance filing to become effective, subject to further modification. TANC asserts that its proposed procedures would mitigate procedural deficiencies which it perceives and would allow the development an adequate evidentiary record. However, some of the expedited procedures TANC recommends, such as the use of Settlement Judges, and other settlement procedures, would not provide an

54/ Id.

55/ Of course, with respect to issues that have been raised prematurely, do not preclude the parties from raising such issues again at an appropriate time.

evidentiary record. Moreover, as noted above, we are do not find that the issues raised warrant hearing procedures.

The Commission is mindful of the magnitude of the changes that will be occurring in the California electric market when ISO and PX operations commence. As stated above, we consider careful and ongoing monitoring of the California restructuring to be an important part of our determination to grant interim authorizations at this time. Accordingly, the authorizations we are granting in this order are interim and subject to numerous conditions as well as further modifications if found appropriate as a result of our ongoing

monitoring. We have directed the ISO and PX to provide quarterly updates of progress in implementing their staging plans, numerous studies and reports, and a comprehensive mid-course review, to assist us in closely monitoring ISO and PX operations. If, at any time, the Commission determines that changes to the ISO and/or PX tariffs and agreements are warranted, we will act accordingly. Once the staging and other implementation details have been finalized, the Commission will require a further compliance filing consistent with the Commission's findings. Finally, we reiterate that parties may also raise issues concerning the ISO and PX in the future by filing a complaint under section 206 of the FPA.

II. ISO Principles

In Order No. 888, the Commission set out eleven principles for evaluating future ISO proposals. The Commission stated that these principles are applicable to ISOs that would be control area operators, as in the instant case. The following analysis evaluates the ISO's proposal with regard to the Commission's eleven ISO principles. We note that this section of the Order provides an overview of the principles. With the modifications contained in this section and later sections of the Order, we find that the proposal satisfies our eleven ISO principles. A more detailed discussion of issues related to the ISO principles is contained in later sections of the Order. The ISO principles provide a guidepost for this Commission in evaluating this ISO proposal. However, this proposal presents many compromises between practicality and ideal market structures particularly given the tight time constraints imposed on this process. As we often are required to do, we must judge whether these tensions are acceptable under our statutory responsibilities. The tension among efficiency, practicality and other terms and conditions affecting interstate commerce exists throughout this restructuring effort. The Commission will be observing the results of this balancing effort as this program is implemented. The monitoring and compliance efforts will greatly assist the Commission in determining if a proper balance has been achieved.

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

The proposed ISO will be a not-for-profit, public benefit corporation. Decision-making authority will be split between the ISO Governing Board and the officers of the corporation. The ISO Governing Board will oversee the establishment of the broad operating criteria and protocols while the officers and staff of the ISO are responsible for day-to-day and real-time decisions of the ISO. Article III of the ISO Bylaws establishes the ISO Board of Governors. 56/

The ISO Governing Board will initially be comprised of thirteen different classes, each of which will elect Governors that will represent the class on the board. The classes will represent: (1) IOU Transmission Owners; (2) Municipal Utilities; (3) Governmental Market Participant Entities; (4) Non-Utility Electricity Sellers; (5) Public Buyers and Sellers; (6) Private

Buyers and Sellers; (7) Agricultural End-users; (8) Industrial End-users; (9) Commercial End-users; (10) Residential End-users; (11) End-user At-Large; (12) Public Interest Groups; and (13) Non-Market Participants. 57/ In addition, the President of the ISO will be a member of the ISO Governing Board. Finally, the ISO Bylaws provide that the Oversight Board will select a Chairperson of the ISO Governing Board. The ISO Bylaws provide that the Chairperson will either be appointed from among the members of the Governing Board or may be appointed as an additional member of the Governing Board, in which case the number of Governors will increase by one. A majority vote is needed for approval of an ISO Governing Board action. The Governors will vote individually, not as a class. There will initially be a maximum of thirty-one members on the Governing Board. 58/

IOU Transmission Owner Class

The IOU Transmission Owner class will initially have three Governors (PG&E, SoCal Edison and SDG&E will each designate a Governor). If the number of Participating IOU Transmission Owners increases to four, the number of Governors in this class will increase to four. If five or more IOU Transmission Owners transfer control of their transmission facilities to the ISO,

56/ The revised ISO Bylaws are contained in Attachment I of the ISO/PX's M 20, 1997, Response to Request For Additional Information.

57/ ISO/PX Attachment I at 3-12.

58/ Id. at 3.

voting for directors within the class will be weighted according to the MW-circuit miles of transmission facilities placed under the ISO's control.

Municipal Utilities Class

The Municipal Utilities class will include any municipality or municipal corporation, municipal utility district, public utility district or irrigation district, or any joint powers authority that includes one or more of these entities. In each case the entity's service area will be within the ISO Controlled Grid. The Municipal Utilities class will have four Governors. The voting mechanism to determine the election of Governors for the Municipal Utilities class will be as agreed to by the class.

Government Market Participant Entities Class

The Governmental Market Participant Entities class will initially have one Governor. If one or more governmental entities transfer control of their transmission facilities to the ISO, then the number of Governors from this class will increase

to two.

Non-utility Electricity Sellers Class

The Non-utility Electricity Sellers class is comprised of independent power producers, qualifying facilities, exempt wholesale generators, and non-utility generators. Utilities that participate in another class and their affiliates and municipal utilities or governmental entities and their affiliates shall not be eligible to participate in this class. Eligible entities will be those entities that have utilized the ISO within the past twelve months for energy-related purposes. The Non-utility Electricity Sellers class will have two seats on the ISO Governing Board.

Public Buyers and Sellers Class

Entities that have purchased or sold wholesale energy using the ISO Controlled Grid during the past twelve months will be eligible to vote for the one Governor to represent the Public Buyers and Sellers class.

Private Buyers and Sellers Class

The Private Buyers and Sellers class will have one seat on the ISO Governing Board. The Private Buyers and Sellers class will represent all private entities, including power marketers, that use the ISO to buy or sell energy and other related services.

End-Users Classes

End-users will be represented on the ISO Governing Board by five classes: Agricultural End-users, Industrial End-users, Commercial End-users, Residential End-users, and End-user At-Large. Each of the end-user classes will have one seat on the ISO Governing Board, except the End-user At-Large class, which will have four seats.

Public Interest Groups and Non-Market Participants Class

Public Interest Groups and Non-Market Participants will each be a class and will be represented by two Governors each on the ISO Governing Board.

Contested Issues Identified by the ISO/PX 59/

Numerous parties raise concerns over the class and voting structure of the ISO. CIU contends that the ISO and PX Boards are insufficiently comprised of representatives of purchasers of transmission and PX services. 60/

EPUC requests a change in the selection of representatives for the Non-utility Electricity Sellers Class to provide that one representative will be selected by voting weighted according to the sales of class members and the second selected by unweighted voting by all class members. 61/ CIU, ECI, and EPUC contend that an entity that satisfies the criteria for more than one class

59/ Contested Issues Identified by the ISO/PX are listed in Appendix I of the August 15 filing, and reflect comments filed by the parties on o about June 6, 1997.

60/ CIU at 11-13.

61/ EPUC at 47.

should be permitted to vote in more than one class. 62/ SRP contends that there should be a designated representative from the WSCC on the ISO Board. 63/ TURN suggests that both the ISO and PX boards are so large as to be unworkable. 64/ The California Commission suggests that the Commission commit now to a formal three-year review of the ISO and PX Board structure. 65/

ECI contends that a representative should not be permitted to serve on both the ISO and the PX Boards, since this would violate the Commission's prohibition against public utility employees performing both a sales and transmission function. 66/

Southern Cities/Azusa and Banning contend that the ISO and PX Boards should not be permitted to delegate decisional authority to committees. Southern Cities/Azusa and Banning are concerned that ISO Governing Board committees may not reflect the diverse representation of the Governing Board. 67/ BPA, SRP, Western and PacifiCorp urge the Commission to reject the ISO and PX's request for reconsideration of the Commission's decision to reject the California residency requirement for ISO and PX Board members. 68/ CCEM and ECI argue that the Commission should also reject the ISO's request to reconsider the Commission's rejection of post-organization activities by the Oversight Board. 69/

Finally, Turlock contends that only a 25% rather than a majority vote of the ISO Audit Committee should be required to call an audit. Specifically, Turlock claims that the threshold level for calling an audit in ISO Tariff Section 12.2.4 is unnecessarily high and fails to protect minority rights. 70/

June 23, 1997 ISO/PX Reply Comments

62/ CIU at 13; ECI at 10; and EPUC at 49.

63/ SRP at 17.

64/ TURN at 12.

65/ California Commission at 23.

66/ ECI at 10.

67/ Southern Cities/Azusa and Banning at 8.

68/ BPA at 90; SRP at 16; Western at 88; and PacifiCorp at 12.

69/ CCEM at 6; and ECI at 9.

70/ Comments of Turlock at 50.

The ISO/PX states that CIU's recommendation is predicated on the concern that unless a majority of the ISO Governing Board is comprised of Governors representing transmission and PX customers, insufficient attention will be paid to containing costs. The ISO/PX states that while such an objective is important, the purpose of a balanced Board is to ensure that other interests including fair and non-discriminatory access to transmission and ancillary services are also met. The ISO/PX states that CIU's proposal to add more end-user representative will bias the ISO toward end-users and thereby violate the Commission's first ISO principle. 71/

The ISO/PX requests that the Commission decline to act on EPUC's, CIU's, ECI's, and SRP's recommendations. The ISO/PX argues that Commission action would result in unnecessary micro-management of Board activities. The ISO/PX states that the California Commission's request is unnecessary because the ISO and PX Governing Boards are required by The California Restructuring Legislation to review the Board structures after three years of operations. 72/

The ISO/PX urges the Commission to reject ECI's recommendation that board members be prohibited from serving on both the ISO and PX Governing Boards. The ISO/PX states that it is difficult to understand how an ISO Governor who also sits on the PX Board can obtain commercially advantageous information. The ISO/PX argues that both Boards act in open meetings and that other Governors representing all other interests sit on the same boards and receive the same information. In addition, the ISO/PX states that all Governors are under duty not to disclose confidential information. 73/

With respect to Southern Cities/Azusa and Banning's recommendation that the ISO and PX Governing Boards be prohibited from delegating authority to committees, the ISO/PX states that the value of delegating decisional responsibility to committees has worked to date and has allowed the boards to successfully fulfill their duties. 74/

The ISO/PX argues that BPA, SRP, Western, and PacifiCorp did not address the merits of the ISO/PX's argument that the

Commission should reconsider its ruling on the Residency Requirement. The ISO/PX states that these parties failed to

71/ ISO/PX June 23, 1997 Reply Comments at 335.

72/ ISO/PX June 23, 1997 Reply Comments at 336.

73/ ISO/PX June 23, 1997 Reply Comments at 337.

74/ ISO/PX June 23, 1997 Reply Comments at 338.

address their statement that there is no nexus between the requirement and the prohibition against unduly discriminatory rates and terms and conditions of service as proscribed by the FPA. The ISO/PX reiterates that the need for the ISO to interact with entities in other regions is not a reason to eliminate the California residency requirement. In addition, the ISO/PX argues that it is because of the ISO's participation in regional coordination that it must be a strong advocate of California interests. Finally, the ISO/PX states that Southern Cities/Azusa and Banning's contention that there is a conflict between the residency requirement and the ISO Bylaws is incorrect because the Bylaws were subsequently revised. 75/

The ISO/PX urges the Commission to reject CCEM and ECI's argument that the ISO/PX's request for reconsideration of the Commission's ruling regarding the post-organizational activities of the Oversight Board was untimely. The ISO/PX argues that Section 385.212 of the Commission's Rules of Practice and Procedure provides that a motion may be filed at any time, unless otherwise provided. The ISO/PX states that the only way that the Commission could conclude that the request was untimely would be to find that the ruling proscribing post-organizational activities by the Oversight Board constituted a final order subject to appeal under the provisions of the FPA. The ISO/PX also argues that since the ISO and PX are not yet operational, there is no compelling reason that the Commission should foreclose its consideration of the motion for reconsideration. 76/

The ISO/PX states that CCEM's suggestion that actions taken by the Oversight Board have not been properly submitted to the Commission as required under the November 26, 1996, Phase I Order is unfounded. The ISO/PX also contends that CCEM and ECI's suggestion that the Oversight Board has a responsibility to submit to the jurisdiction of the Commission and file its articles of incorporation and Bylaws is based on a misunderstanding of the legal status of the Oversight Board. The ISO/PX states that the Oversight Board has no articles of incorporation or Bylaws and that it is a creation of the state of California, as provided in Section 335 of The Restructuring Legislation. 77/

Finally, the ISO/PX contends that Turlock's recommendation with regard to reducing the threshold level for calling an audit may lead to an increased number of interim audits being called.

75/ ISO/PX June 23, 1997 Reply Comments at 334.

76/ ISO/PX June 23, 1997 Reply Comments at 346-347.

77/ ISO/PX June 23, 1997 Reply Comments at 346.

The ISO/PX states that a majority vote is a normal and common sense formula. 78/

September 2, 1997 Comments

The Oversight Board opposes SRP s proposal to require a member of WSCC to be provided a vote on the ISO Governing Board to represent reliability interests. According to the Oversight Board, the Governing Board has a fiduciary responsibility to meet the ISO s statutory, regulatory and contractual obligations. Therefore, the Oversight Board believes that the Governing Board will have a significant interest in system reliability. The Oversight Board also contends WSCC will have adequate input in ISO Governing Board decisionmaking, because the ISO has taken steps to obtain an expert independent staff, to create a consultative relationship with the WSCC, and toward becoming a member utility of that body. 79/

ECI reiterates its position that the Commission and not a state-created entity, is the more appropriate forum for hearing challenges to ISO Governing Board decisions. 80/

The Oversight Board opposes proposals by CIU and EPUC that an entity should be allowed in more than one class during the director selection process. The Oversight Board also opposes a suggestion by CIU that allowing such changes would be acceptable if the Commission also requires that an entity may only seek to be selected to the Governing Board in one class. The Oversight Board points out that Governing Board members are individual persons, rather than entities, and that Governing Board members are subject to fiduciary duties to the ISO or the PX equivalent to those of a trustee. 81/

The Oversight Board argues that ECI s proposal to prohibit persons from serving on both the ISO and PX Governing Boards is unnecessary. In response to ECI s contention that members of the PX Board could have access to non-public ISO information that could benefit the PX as a Scheduling Coordinator, the Oversight Board contends that dual directorship during the developmental phase of the ISO and PX could avoid developmental pitfalls, that most board activities occur in open public meetings, and that all

78/ ISO/PX June 23, 1997 Reply Comments at 282.

79/ Oversight Board at 3.

80/ ECI at 13-14.

81/ Oversight Board at 2.

directors are subject to Code of Conduct provisions prohibiting use of information to benefit an outside entity. 82/

Commission Response

In the November 26 Order, the Commission rejected the California residency requirement for Governors of the ISO and PX. 83/ There, the Commission found that ISO and PX Boards will affect matters within the Commission's exclusive jurisdiction, that the Commission must eliminate any unduly discriminatory or preferential provisions that relate to the Governing Boards that will oversee jurisdictional activities, and that the residency requirement is such an unduly discriminatory and preferential provision. Moreover, the Commission found that the residency requirement is inconsistent with the primary goal in Order No. 888 to provide for broad based non-discriminatory open-access transmission services and would act to discourage participation in the ISO by out-of state entities by denying them meaningful representation. No requests for rehearing were filed regarding this ruling. 84/

The ISO and PX Bylaws both continue to include the residency requirement. In the March 31 filing, the ISO/PX seeks reconsideration of our ruling, 85/ claiming that the undue discrimination provisions of sections 205 and 206 of the FPA relate only to preventing unduly discriminatory or preferential treatment in rates or conditions of service, and do not apply to the Board composition; that the ISO and PX Governing Boards are the policy bodies accountable to the State Government for directing the activities of the ISO and PX, that the State of California has legitimate concerns expressed in the Restructuring Legislation to ensure efficient and reliable service to California consumers; and that the purpose of the ISO and PX Governing Boards is to serve the interests of California consumers, their primary constituency. 86/ Moreover, the ISO/PX contends that the residency requirement is called for where the ISO will be interacting with other entities in the region outside of California. The ISO/PX contends that it is necessary for the ISO to adequately represent the interests of the State in

82/ Oversight Board at 4.

83/ November 26 Order, 77 FERC at 61,819.

84/ We reject the ISO/PX contention that our November 26 ruling on this issue was not final.

85/ The ISO and PX did not seek rehearing of this determination.

86/ March 31 filing at 28-30.

negotiating such compacts, and that adjoining states are more likely to join with a California ISO as an equal partner than with an ISO in California that purports to already have wider representation.

On December 26, 1996, California Senator Steve Peace, Chairman of the Senate Committee on Energy, Utilities and Communications; Terry Winter, (then Director of Power Operations for SDG&E, now the Chief Operating Officer for the ISO); Steve Kline, VP of Regulation for PG&E; and Robert G. Foster, Senior VP, Public Affairs for SoCal Edison filed a letter with the Commission (California letter) stating that the residency requirement and post-operational functions of the Oversight Board should be maintained. According to the California letter, the Restructuring Legislation considers the ISO and PX initially to be State bodies rather than regional bodies, which must be chartered under California law. In addition, they point out that the Restructuring Legislation encourages California's municipal utilities to commit control of their transmission assets to the ISO and opens markets of the state's municipal and investor-owned utilities to retail competition, which are actions that only California can require. The California letter acknowledges that the ISO may take on a regional character in the future and welcomes out of state governance at that time through the vehicle of interstate compacts. However, the California letter argues that the ISO should not be regionalized without assurances of adherence to direct access reciprocity by non-California utilities and performance of the ISO's legislatively mandated reliability functions, including review and sanction of utility reliability performance. Otherwise, California citizens are at risk of remotely originated outages without adequate safeguards. Also, the California letter maintains it would give non-California utilities access to California retail markets without reciprocal access.

In response to the California letter, DuPont Power Marketing, Inc./Mock Energy Services, L.P.; ECI; National Gas & Electric; Portland General Electric; and Washington Water Power state their concern that the residency requirement and expanded Oversight Board functions may preclude or limit non-California entities from participating effectively, which would ultimately frustrate safe, reliable low-cost power to California consumers. In particular, these commenters state that a regional approach to problems must be the initial basis for developing an effective ISO. The failure to coordinate in-state scheduling procedures with that of out-of state transmission lines will make it impossible for many potential competitors to bid, resulting in higher California energy prices, less economic efficiency, and a piece-meal approach to deregulation that will usher in electricity competition one state at a time.

The Oversight Board supports the ISO/PX request for reconsideration of our ruling rejecting the residency requirement, arguing that it is not discriminatory within the scope of sections 205 and 206 of the FPA which prohibit discrimination by a corporation in providing service but do not affect otherwise lawful requirements for directors of such corporations. In addition, the Oversight Board contends that Central Iowa Power, cited in the November 26 Order, 87/ is not dispositive, because it presented a different situation, in which membership class conferred particular rights on participants. The Oversight Board contends that the legal duties of a director require directors to act on behalf of the corporation and prohibit directors from attempting to exercise their powers on behalf of any particular outside entity. 88/

As a preliminary matter, we note that no party sought rehearing of our determinations concerning the California residency requirement and Oversight Board responsibilities discussed infra. As a result, we reject the pleadings as untimely rehearings. We address the arguments raised on reconsideration in the interests of comity and to provide guidance to other states considering restructuring activities.

We deny reconsideration of our ruling rejecting the California residency requirement. We acknowledge the ISO/PX representations that the ISO and PX Governing Boards are "policy bodies accountable to the State Government." However, these entities direct and control public utilities subject to the Commission s jurisdiction and therefore affect rates, terms and conditions of jurisdictional service (see FPA section 205(c)). Therefore, the State of California s expressed purpose that these entities represent primarily the interests of California consumers is not controlling when that purpose may result in unduly discriminatory or preferential treatment of Market Participants.

The ISO/PX arguments that the provisions of section 205 and 206 of the FPA do not apply to the residency requirement are wrong. First, contrary to the ISO/PX s assertion, our mandate to preclude undue discrimination is not strictly limited to rates and terms and conditions of service per se. As we stated in our November 26 Order, restrictive membership provisions in a power pooling agreement have been found to be unduly discriminatory under the FPA. Contrary to the Oversight Board's assertions, the

87/ See Central Iowa Power Coop. v. FERC, 606 F.2d 1156 (D.C. Cir. 1979) (Central Iowa Power), in which the court upheld the Commission s determination that a restrictive membership provision in a power poo agreement was unduly discriminatory under the FPA and must be modifi

88/ Oversight Board June 6 Comments at 9-10.

court's ruling in Central Iowa Power precludes membership restrictions that will result in unduly discriminatory or

preferential treatment.

Second, the ISO/PX contention that the Governing Boards "have no role relating to terms and conditions of service to consumers outside of California" is simply incorrect. The ISO and PX tariffs will affect the terms and conditions under which suppliers and consumers outside of California will be able to participate in the California market. The ISO Tariff provisions will affect the rates, terms and conditions of service to consumers outside of California where energy is transmitted from or through California. Moreover, the PX Tariff does not exclude load outside of California. The ISO/PX and the California letter both assert that the residency requirement is consistent with the purpose of the ISO and PX set forth in the Restructuring Legislation to promote the interests of California consumers. However, we believe this stated purpose may place the interests of California consumers ahead of the interests of non-California entities that participate in ISO and PX operations. Therefore, we continue to believe that the residency requirement will preclude these non-California Market Participants from effective participation in the ISO and PX, in violation of ISO Principle 1.

Nor do we accept the ISO/PX arguments that the residency requirement is necessary to enable the ISO and PX to adequately represent the interests of California consumers in negotiating with other states. The ISO and PX are well aware that other states are joining together in forming their own Independent System Operators, and that in many cases, the ISO and PX will be negotiating with other regional, rather than state, bodies. The ISO and PX are in no different position than these other entities.

Accordingly, we deny the motions for reconsideration of the residency requirement. The ISO and PX must remove the residency requirement from their respective Bylaws.

We also deny the ISO/PX request for reconsideration of the Commission's limitation on the role of the California Oversight Board. In the November 26 Order, the Commission stated that we will afford great weight to the California Legislature s views as expressed in the Restructuring Legislation. Accordingly, the Commission agreed to allow the Oversight Board to perform an initial start-up function, subject to the Commission s final review. However, the Commission rejected the continuing role of the Oversight Board in governance and operations, because these duties, which would be conducted by a State-created Oversight Board consisting of appointees of the State legislature and the Governor of California, would conflict with the Commission s statutory duties under the FPA. Moreover, the Commission found that the continued role of the Oversight Board may delay or

conflict with the Commission s stated intention to regulate ISOs. Accordingly, the Commission directed the ISO and PX to provide governance and dispute resolution procedures that do not involve the Oversight Board. 89/ No requests for rehearing of this ruling were filed. 90/

Nevertheless, the ISO and the PX Bylaws continue to provide for a continuing role of the Oversight Board in the appointment of Governors and in hearing appeals of Board determinations, contrary to our earlier ruling. 91/ The ISO and PX Governing Boards now seek reconsideration of this ruling, claiming that the Oversight Board is the arm of the State Government designated to oversee the role of the ISO in protecting reliability. 92/ The ISO/PX also notes that the appellate function of the Oversight Board would not replace the right to appeal to the Commission. However, the Oversight Board would be able to overturn an ISO Governing Board decision and remand it back to the ISO Governing Board. 93/ The ISO/PX contends that the continued role of the Oversight Board does not interfere with Commission jurisdiction, but permits a very new and untested corporation to receive oversight to assure that it is carrying out very important state laws. 94/

The California letter, mentioned above, also opposes the Commission's limitation on the functions of the Oversight Board. The California letter recognizes the Commission's appellate function and states that the limited review responsibilities of the Oversight Board are intended as an extension of the ADR process. The letter also states that the Oversight Board is intended to help establish the ISO and PX, preserve electric system reliability, and restructure the electric industry on a competitive basis, all subject to Commission jurisdiction and oversight.

89/ November 26 Order, 77 FERC at 61,817-18.

90/ We reject the ISO/PX contention that our November 26 ruling was not final.

91/ See, e.g., Sections 3, 4, 6, 7 and 13 of the ISO Bylaws and Sections 3, 4, 6, 7, and 13 of the PX Bylaws.

92/ As noted above, the Commission rejects the pleadings as untimely rehearings. We address the arguments raised on reconsideration in t interest of comity and to provide guidance to other states.

93/ March 31 Filing at 27.

94/ Id.

The Oversight Board supports the ISO/PX position. The Oversight Board claims that its continued role would ensure the independence and public responsibility of the ISO and PX while allowing participation by stakeholder groups. The Oversight Board also maintains that its continued oversight over system reliability falls squarely within traditional state jurisdiction, and would allow the ISO to have flexibility. 95/ Finally, the Oversight Board stresses that its appellate role would not conflict with the Commission's jurisdiction, because its "[c]onsideration of an appeal clearly would not be undertaken in

a manner that would result in a violation of the FPA or any other federal law." The Oversight Board states that its appellate function would serve to protect certain state interests without diminishing the Commission's authority to exercise jurisdiction over Commission jurisdictional issues.

We deny the motions for reconsideration of our earlier determination to limit the Oversight Board's functions. The arguments raised by the ISO/PX, the California letter, and the Oversight Board, emphasize the importance of ensuring reliability of the ISO grid. However, this objective is at best only remotely related to the ISO and PX Bylaws provisions requiring Oversight Board confirmation of Board members that may or may not serve particular California interests, or allowing appeals of Governing Board decisions to the Oversight Board. 96/ While a properly constituted Oversight Board with an appropriately formulated role may be acceptable in certain circumstances, and would not interfere with the Commission's jurisdictional responsibilities, in this case the Oversight Board is not properly constituted, 97/ and would detract from the independence of the ISO and PX Governing boards. Therefore, the ISO and PX Bylaws must be modified to remove the continuing Oversight Board functions, consistent with our earlier ruling.

With these revisions, we find that the proposed governance structure is consistent with Order No. 888, ISO Principle No. 1 and our November 26 Order. As required in our November 26

95/ Oversight Board June 6 Comments at 5-6.

96/ We note that the ISO and PX have committed to comply with all NERC a WSCC reliability criteria as well as the Companies' individual reliability criteria.

97/ As noted in our November 26 Order, the Oversight Board would consist three California electricity ratepayers who would be appointed by th Governor, and confirmed by the California Senate, plus a non-voting member of the Senate and one non-voting member of the Assembly. The Oversight Board is unacceptable, among other things, because it appe to be designed to favor California interests rather than the interes of all users of the ISO and PX.

Order: (1) no one voting class will be able to block or veto an action; (2) no two classes together will be able to form a sufficient majority to make decisions, and (3) no entity (including its affiliates and subsidiaries) will be able to participate in more than one voting class.

We also accept the ISO proposal, as supported by the California Commission, 98/ to submit to the Commission, no later than three years after adoption of the ISO Bylaws, a recommendation as to whether the proposed class structure requires modification. We note that this commitment in no way precludes any person from filing a complaint under section 206, or the Commission on its own motion instituting an investigation under section 206, regarding the governance structure. With

regard to TURN/UCAN's concern that the ISO Governing Board is so large as to be unworkable, we find TURN/UCAN's concerns to be premature. 99/ As noted above, to the extent the Commission or any other entity has concerns about the ISO Governing Boards' structure, it may institute, or file a complaint seeking, respectively, a section 206 proceeding to review the boards' class structure. 100/

We disagree with EPUC that voting for one of the two representatives from the non-utility sellers class be weighted according to sales. 101/ We find that the one-vote per entity is both fair and reasonable and will prevent large sellers from dominating the class. We also disagree with EPUC's, CIU's, and ECI's suggestion that entities should be permitted to vote in more than one class. 102/ This recommendation is contrary to our finding in the Phase I order. With regard to CIU's contention that the ISO and PX Boards have insufficient representation from purchasers of transmission and PX services, we agree with the ISO/PX that representation on the ISO Board of these interests is

98/ Comments of California Commission at 31.

99/ Comments of TURN at 12.

100/ We note that TURN raises similar concerns with regard to the PX Governing Board. We find that our conclusions with regard to the IS Governing Board are equally applicable to the PX. To the extent the Commission or any other entity has concerns about the PX Governing Boards' structure, it may institute a section 206 proceeding, or fil complaint under section 206, respectively, to review the boards' cla structure.

101/ Comments of EPUC at 47.

102/ Comments of CIU at 12; ECI at 10; and EPUC at 49.

sufficient. 103/ With regard to SRP's recommendation that the WSCC have a designated representative on the ISO Board, we note that nothing would prohibit a WSCC representative from becoming a Governor of the Non-Market Participants class. 104/ In addition, in light of the fact that the ISO will be a member of the WSCC, we believe that SRP's recommendation is unnecessary.

ECI requests that the Commission prohibit a representative from serving on both the ISO and PX Boards. 105/ ECI states that permitting representatives to sit on both boards would violate the Commission's proscription against a public utility employee from performing both sales and transmission functions. We disagree with ECI. As noted by the ISO/PX, Governors will not be able to independently obtain commercially advantageous information since the ISO Governing Board acts in open meetings and all board members will receive the same information. Moreover, as noted by the ISO/PX, all Governors are prohibited from divulging commercially sensitive information. Governors

will not be involved in the day-to-day operation of the ISO and therefore generally will not have access to information that could be utilized in the proposed daily or hourly market. 106/ However, we note that the ISO and PX are separate public utilities. Should a director sit on both the ISO and PX Governing Boards or simultaneously sit on the board of another public utility, the director must file an application pursuant to section 305(b) of the FPA and under Part 45 of the Commission's Regulations.

We disagree with Turlock's recommendation with regard to reducing the threshold level for calling an audit. We agree with the ISO/PX that Turlock's recommendation may lead to an increased number of interim audits being called and that this is not an efficient use of ISO resources. In addition, we disagree with Turlock that the majority vote requirement will diminish the rights of minority members. All ISO participants, regardless of their size, have an interest in the ISO's compliance with all of its operational policies and procedures. To the extent a member raises legitimate concerns with regard to the ISO's operation, that entity should have little trouble in securing a majority of the members in order to initiate an audit.

103/ Comments of CIU at 11-13. ISO/PX Reply Comments at 335. Similarly, w find that the PX Governing Board has sufficient representation from these interests.

104/ Comments of SRP at 18.

105/ Comments of ECI at 10.

106/ Similar restrictions would also prohibit a PX Governing Board member from utilizing sensitive market information.

The Role of Committees

In a related matter, a number of intervenors question the role and authority of the various committees (referred to as a Committee of Governors in the ISO Bylaws) established under the ISO's proposed governance structure. Specifically, Southern Cities/Azusa and Banning object to provisions in the ISO's Bylaws which permit the board to delegate decisional authority to committees. 107/ Southern Cities/Azusa and Banning are concerned that committees may not be representative of the Governing Board and request that committee decisions be subject to approval or ratification by the Governing Board.

Commission Response

We disagree with the Intervenors. We find the formation of such committees with specific areas of expertise to be appropriate. The procedure for establishing committees appears reasonable. Article IV Section 1 Committee of Governors of the ISO Bylaws states in part that:

In appointing committee members, the Governing Board shall, to the extent practicable, ensure that the composition of the committee reflects the broad range of entities representing all Classes which express interest in participating in that committee.

Moreover, the ISO Bylaws require a two-thirds vote of the Governors in order to establish a Committee of Governors. While the ISO Bylaws provides that a Committee of Governors shall have the authority of the Governing Board, that authority is appropriately limited under Article IV Section 1 parts (a) through (f). 108/ In addition, under the ISO Bylaws all meetings of committees have to be appropriately noticed and the minutes of any meeting have to be promptly sent to each Governor and filed with the corporate records. To the extent any Governor questions the actions or decisions of a particular committee, there is no provision in the ISO Bylaws which would prevent that Governor from raising his/her concern at the next ISO Governing Board meeting.

107/ Comments of Southern Cities and Azusa and Banning at 8.

108/ We note that under the ISO Bylaws all Advisory Committees, the ADR Committee, and the Audit Committee will not have the authority to ac for the ISO Governing Board. We direct the ISO to include a clean (not blacklined) version of the ISO Bylaws in its compliance filing.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

As noted above, the proposed ISO will be a not-for-profit, public benefit corporation and therefore will have no financial interest in any market participant. Exhibit A of the ISO Bylaws contains the Code-of-Conduct applicable for ISO officers, employees and full-time consultants and contractors (Employees). Exhibit B of the ISO Bylaws contains the Code-of-Conduct for the ISO Governors.

Under the ISO Employee Code-of-Conduct, all Employees must apply the terms and conditions of the ISO Tariff, including requests for service, on a non-discriminatory basis. In addition, if any provision of the ISO Tariff requires the exercise of discretion, all Employees will apply the tariff provision in the same manner to the same or similarly situated persons. To the extent a tariff provision does not require the exercise of discretion, the Code-of-Conduct requires that all Employees strictly enforce that provision of the ISO Tariff. ISO Employees are prohibited from buying or selling energy for others or acting as an energy broker.

Unless approved by the ISO Governing Board, no Employee of

the ISO may be an employee of an entity engaged in the generation, transmission, marketing or distribution of electricity. In addition, no person may become an ISO Employee unless they agree in writing to dispose of securities issued by a Market Entity with a fair market value in excess of the lower of the following caps: (1) 10 percent of that person's net worth; or (2) $25,000, adjusted from January 1, 1997, by the Consumer Price Index. The Employee is allowed between four and six months to dispose of these assets from the time the person works for the ISO. The same limitations are applicable to a current Employee that wishes to acquire securities of a Market Entity.

The ISO's proposed Code-of-Conduct for Governors on the ISO Governing Board is similar to that proposed for employees except that Governors are not subject to any financial conditions during their term in office (e.g., securities ownership restrictions and financial reporting requirements).

Commission Response

Because the ISO is structured to have an interested Governing Board, we will allow board members to own securities of Market Entities. However, we direct the ISO to revise the Governors Code of Conduct to require that each Governor file a publicly available annual disclosure statement that identifies

all of his/her investments in Market Participants, broken down by ISO Governing Board class structure. 109/

We reject the ISO's proposal to allow Employees to possess securities of market participants. In Order Nos. 888 and 888-A, the Commission emphasized that ISO employees should be financially independent of market participants and that compliance with ISO Principles Nos. 1 and 2 is fundamental to ensuring that an ISO is truly independent and would not favor any class of transmission customers. We noted, however, that a short transition period may be needed for employees of a newly formed ISO to sever all ties with former transmission owners. 110/ The Commission recognized that some flexibility may be necessary regarding the length of a transition period, but that ISO employees must "in fairly short order" be independent of all financial ties to market participants. 111/ The ISO's proposal to permit employees to retain securities of market participants is inconsistent with the principle of a truly independent ISO. The ISO/PX has provided no justification for waiving this requirement. Therefore, we direct the ISO to modify its Code-of-Conduct for employees so that all ISO employees must divest themselves of all securities issued by a market participant within six months of that person becoming an employee of the ISO (or six months from the date of this order for existing employees). 112/

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that

applies to all eligible users in a non-discriminatory manner.

The ISO states that all eligible customers will have access to the ISO Controlled Grid on a non-discriminatory basis through the ISO Tariff and Operating Agreement. Under the ISO's proposal, transmission customers pay an access charge based on

109/ Similarly, while we will permit PX Governing Board members to own securities in Market Participants, we require the PX to amend the Governors Code of Conduct to require the filing of an annual disclos statement.

110/ Order No. 888, FERC Stats. & Regs. □ 31,036 at 31,731.

111/ Order No. 888-A, FERC Stats. & Regs. □ 31,048 at 31,249-50.

112/ We find that PX employees should similarly be prohibited from owning securities in any Market Participant. We direct the PX to modify it Employee Code of Conduct to state that all PX employees must divest themselves of any securities of any Market Participant.

the rolled-in embedded cost of the Transmission Owner's transmission system where the scheduled power leaves the ISO Controlled Grid. Therefore, the ISO maintains that all transmission customers will have access to the entire ISO Controlled Grid at non-pancaked rates. 113/ In addition, as discussed above, the ISO will also provide ancillary services. 114/

Commission Response

We agree that the ISO's proposed transmission access fee proposal will provide for access to the entire ISO Controlled Grid at non-pancaked rates. Moreover, we agree with the ISO that all transmission customers will have access to the ISO Controlled Grid and all ancillary services provided by the ISO under the ISO Tariff on a non-discriminatory basis. Therefore, we find that the ISO's proposal satisfies Principle No.3 of the Commission's ISO Principles.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

The ISO will be responsible for control area operations and will satisfy all Western System Coordinating Council (WSCC), North American Electric Reliability Council (NERC), and local reliability requirements and operating guidelines. The ISO will have exclusive authority to control not only transmission facilities, but all other facilities that affect the reliability

of the ISO Controlled Grid. Under the ISO's proposal, all Market Participants will be obligated to carry out orders given by the ISO in order to maintain system reliability. In order to fulfill its obligations, the ISO will continuously monitor and control the system through Energy Management System (EMS) computers, telecommunications equipment, and System Control And Data Acquisition (SCADA) equipment. The ISO will have the ability to commit and control the output of certain "Reliability Must Run" generating units required for reliability. In addition, the ISO

113/ The access charges for PG&E, SDG&E and SoCal Edison will be based on t transmission revenue requirement for each utility as established in Docket Nos. ER97-2358-000, ER97-2364-000, and ER97-2355-000, respectively.

114/ PG&E's, SDG&E's and SoCal Edison s ancillary service rates will be established in Docket Nos. ER97-2358-000, ER97-2364-000, and ER97-23 000, respectively.

will control the output of generation for ancillary services or congestion redispatch. The ISO will also be able to curtail certain loads voluntarily designated.

Finally, the ISO will be responsible for coordinating and approving maintenance schedules. As proposed, the ISO may, at its discretion, reject any requests for removing equipment from service if it believes that such removal may jeopardize system security. The ISO will schedule all transmission system maintenance. The ISO will also establish guidelines applicable during emergency conditions and will define all requirements necessary to enable and maintain communications during such emergencies.

September 2, 1997 Comments

Numerous intervenors raise concerns over the requirement that all participants must comply with all ISO operating orders except those that may result in impairments to health and safety. 115/ Intervenors generally argue that participants should not be required to comply with the ISO's orders if those orders will result in damage to that participants facilities.

Western is also concerned that the ISO's role as maintenance coordinator is overly broad. Western states that the definitions of Outage and Forced Outage do not distinguish between outages of transmission facilities and those of generation and distribution facilities. Western recommends that the ISO Tariff be amended to provide that the ISO will coordinate maintenance for only those facilities that either comprise the ISO Controlled Grid or have a high probability of affecting the reliability of the grid. Western also states that parties could mutually agree with the ISO to coordinate on the maintenance of their facilities. 116/

Commission Response

The ISO has proposed reliability standards which adopt those prescribed by NERC and the regional reliability council, the WSCC. Under the ISO's proposal the ISO will be responsible for maintaining the reliability of the transmission system and for scheduling maintenance. In addition, the ISO will establish clear protocols and guidelines to be applied during system emergencies. We find that the ISO's proposed standards and procedures satisfy ISO Principle No. 4.

115/ See, e.g., September 2, 1997, Comments of Western at 39-40; TANC at 38 41.

116/ September 2, 1997, Comments of Western at 40-41.

We find that the requirement that participants comply with all ISO orders except those that would result in impairment to public health or safety to be reasonable. With regard to intervenor concerns about potential damage to their facilities, we note that the ISO will follow good utility practice in operating the system and will comply with all NERC, WSCC and other reliability criteria. Section 5.1.3 of the Transmission Control Agreement states in part that:

> It [the ISO] shall act in accordance with Good Utility Practice, applicable law, the ISO Tariff and the Operating Procedures. The ISO shall not direct a Participating Transmission Owner to take any action which would require a Participating Transmission Owner to operate its transmission facilities in excess of their applicable rating as established or modified from time to time by the Participating Transmission Owner.

We anticipate that the ISO will operate the facilities under its operational control consistent with this provision. Moreover, we believe that it is essential that participants follow all orders given by the ISO, unless they would result in impairment to public health or safety, since otherwise the ISO will be unable to effectively manage and control the ISO Controlled Grid.

We find that Western's clarification is unnecessary and that the ISO's role in coordinating maintenance is not overly broad. Section 2.3.3.1 of the ISO Tariff states that the ISO "shall coordinate and approve Maintenance Outages of all facilities forming part of the ISO Controlled Grid and Reliability Must-Run Units." Moreover, to the extent Western or any other participant has concerns over the ISO's maintenance coordination efforts, Section 2.3.3.6 of the ISO Tariff provides all participants an opportunity to air their concerns with the ISO. We agree with Western that Sections 2.3.3.4 and 2.3.3.9.1 need to be clarified and made consistent with Section 2.3.3.1. Sections 2.3.3.4 and 2.3.3.9.1 of the ISO Tariff state that coordination of all Maintenance Outages and Forced Outages, respectively, will be through a single point of contact. We direct the ISO to add the phrase, "consistent with Section 2.3.3.1" to both Section 2.3.3.4

and Section 2.3.3.9.1 of the ISO Tariff.

We also agree with Western that Section 2.3.3.5 of the ISO Tariff is not entirely clear with regard to an Operator's ability to schedule a Maintenance Outage. An Operator should have the flexibility to schedule maintenance on its facilities as conditions warrant; not all maintenance can be scheduled up to a year in advance. Therefore, we direct the ISO to add the following additional sentence to Section 2.3.3.5 of the ISO Tariff:

> An Operator may, upon 72 hours advance notice, schedule with the ISO Outage Coordination Office a Maintenance Outage on its system, subject to the conditions of Sections 2.3.3.5.1, 2.3.3.5.2 and 2.3.3.5.3 below.

We note that under Section 2.3.3.5.1 of the ISO Tariff the ISO is to evaluate, whether a "requested Maintenance Outage or change to an Approved Maintenance Outage is likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid or the facilities of a Connected Entity." In addition, under Sections 2.3.3.5.2 and 2.3.3.5.3 the ISO has the option of either approving or denying the requested Maintenance Outage. If the ISO denies a requested Maintenance Outage, under Section 2.3.3.5.3 that decision is final. We find that with the above changes, the ISO Tariff will permit Participating Transmission Owners to make needed Maintenance Outage schedule changes while still providing the ISO an opportunity to evaluate the impact of such a request on the ISO Controlled Grid.

With regard to Western's concern that Section 2.3.1.3.2 gives the ISO too much discretion in fashioning new reliability criteria, we agree that this section should specifically reference, and be consistent with, Section 5 of the Transmission Control Agreement. Section 5.1.5 of the Transmission Control Agreement provides that the ISO will consult with Participating Transmission Owners and other Market Participants, through the ISO Technical Advisory Committee, in developing and promulgating Applicable Reliability Criteria for the ISO Controlled Grid. In addition, we agree with Western that Section 2.3.5.1.3 of the ISO Tariff should be revised to be consistent with Section 2.3.1.3.2.

As proposed, Section 2.3.5.1.3 of the ISO Tariff provides the ISO with the discretion to impose more stringent reliability criteria without consulting with Participating Transmission Owners and other Market Participants as required under Section 5.1.5 of the Transmission Control Agreement and Section 2.3.1.3.2 of the ISO Tariff. We direct the ISO to revise the parenthetical phrase in the first sentence of Section 2.3.5.1.3 to read, "or such more stringent criteria as the ISO may impose pursuant to Section 2.3.1.3.2."

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

The ISO will initially have control over the transmission facilities of the Companies (identified in Appendix A of the Transmission Control Agreement) and will eventually expand the ISO Controlled Grid to include the transmission systems of all Participating Transmission Owners. The ISO will have complete operational control over the designated transmission facilities.

In addition, pursuant to Section 7.1. of the Transmission Owners' Tariff, the ISO may require that a Participating Transmission Owner make additional facilities on its system available as part of the ISO Controlled Grid in order for the ISO to perform its control area responsibilities. Pursuant to Section 4.5.2 of the Transmission Control Agreement the ISO may also assert temporary control over specified facilities of a Participating Transmission Owner in order to fulfill its control area responsibilities.

Commission Response

The ISO's proposal satisfies ISO Principle No. 5.

6. An ISO should identify constraints on the system and be able to take operation actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

The ISO has proposed a Congestion Management framework that is intended to efficiently manage transmission Congestion. Under the ISO's proposal, the ISO will identify regions on the ISO Controlled Grid that are impacted by transmission constraints. Section 7.2 of the ISO Operating Agreement and Tariff enables the ISO to take all necessary actions to relieve constraints on the ISO Controlled Grid. The ISO is responsible for maintaining schedules over constrained paths or interfaces within acceptable limits.

The ISO has initially divided the ISO Controlled Grid into two Active and two Inactive Congestion Zones. As defined by the ISO, Congestion Zones are areas within which transmission Congestion is small and between which there is limited transmission transfer capability due to constraints on the transmission network. The ISO Tariff states that, if over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path 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 Transmission Owners, the ISO may announce its intention to create a new Zone.

The ISO will impose Usage Charges that reflect the transmission Congestion costs between zones. The ISO will impose Usage Charges on all users of the ISO Controlled Grid who use the constrained interface. The ISO proposes that the Usage Charge be calculated based on the adjustment bids voluntarily submitted by Scheduling Coordinators. Adjustment bids reflect the prices at which Scheduling Coordinators are willing to permit the ISO to change their balanced schedules in order to relieve constraints.

The ISO will use adjustment and ancillary service bids to relieve constraints in real time. Therefore, the Congestion Usage Charge

will be equal to the marginal value of the congested Inter-zonal Interface. The marginal value is defined as "the total change in redispatch costs (based on the adjustment bids) that would result if the interface's scheduling limit was increased by a small increment." 117/ The PX and other Scheduling Coordinators that use the constrained interface would be assigned a Usage Charge.

The ISO contends that the Usage Charges will help send the proper price signals for the siting of generation and for the efficient expansion of the transmission grid. If congestion costs exceed the cost of new transmission facilities that would alleviate a transmission constraint, there will be an incentive for the affected parties to build such facilities.

Commission Response

In our July 30, 1997, order, we accepted the conceptual framework of the ISO's congestion pricing proposal. We stated that the proposal's features are necessary to achieve two important objectives: 1) the proposal efficiently rations constrained transmission capacity; and 2) it provides for the recovery of each Transmission Owner's revenue requirement. In addition we stated that:

> 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. . . Moreover, the ISO's proposed congestion usage charge is also likely to encourage efficient expansion of the transmission system. . .

The proposal for managing Congestion and the proposed delineation of Zones are based on historical patterns of transmission usage. The proposal would impose a Congestion Usage Charge to manage congestion between two Active Zones where Congestion has been significant, but would not impose Congestion Usage Charges to manage Congestion elsewhere. Under the new market structure new patterns of Congestion or problems associated with Congestion may arise, but until experience is gained a comprehensive set of appropriate Congestion Management rules is difficult to develop. In the interim, we are satisfied

117/ Section 7.2.5.2.2 of the ISO Tariff.

that the ISO's proposed Congestion Management proposal complies with ISO Principle No. 6.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open and competitive market.

The ISO Governing Board is charged with developing a long-term staffing and organizational plan. As stated by the ISO/PX, the ISO will implement a performance-based compensation system for management and staff by January 1, 1999. 118/ In addition, the ISO/PX states that the ISO intends to follow competitive procurement practices under its rules, protocols and operations, once developed. 119/

Commission Response

The ISO/PX proposal forms the foundation of an efficient management structure. We recognize that until the ISO determines its staffing requirements and what services are best procured from outside entities, it is difficult to develop a comprehensive management plan. In the interim, we are satisfied that the ISO will be managed in an efficient and independent manner.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct studies as may be necessary to identify operational problems or appropriate expansions.

The ISO proposes a two-part rate for access to the ISO Controlled Grid: 1) an access fee designed to recover the transmission revenue requirement of the Participating Transmission Owners, and 2) a Usage Charge designed to reflect the cost of using a constrained transmission path. The ISO proposes that transmission customers pay the access fee of the transmission owner where the load is located (i.e., where the power leaves the ISO Controlled Grid). With regard to ancillary services, the ISO proposes to conduct a bid-based auction in order to procure the ancillary services necessary to perform its control area responsibilities. The ISO proposes that FERC-

118/ ISO Appendix 6 at 10.

119/ Id.

jurisdictional entities be required to file cost-based rates for ancillary services.

Commission Response

As noted above, we have accepted the conceptual framework of the ISO's transmission pricing proposal. As we stated in our July 30 Order, the ISO's proposal will provide for recovery of a Transmission Owner's transmission revenue requirement and will send the proper price signals with regard to the location and use of existing and future generation, transmission expansion, and consumption. 120/

In the July 30 Order we also approved the ISO's proposed transmission expansion and planning process. As we stated in that order, the ISO's proposal, "is consistent with our directive that the ISO play a role in coordinated transmission system planning, regional coordination, and expansion." In addition, we stated with regard to the ISO's transmission system planning proposal that, "We believe that this proposal appropriately balances the interests of all parties and establishes a clear delineation between the roles of the ISO and WRTA." Finally, we stated that the ISO's initial transmission expansion proposal establishes a realistic and workable regime. 121/

We are satisfied that, for the interim, the ISO's proposal satisfies ISO Principle No. 8. However, as noted in the discussion of Principle No. 6, the proposal for managing congestion, including assessing Usage Charges for transmission across congested interzonal interfaces, has been developed based on historical experience regarding congestion. Usage Charges may play a role in influencing the use of and investment in generation, transmission, and consumption. As conditions change under the new market environment, we will monitor the effectiveness of the ISO's proposal to send efficient price signals. Further, as noted elsewhere in this Order, we are requiring the ISO to conduct studies to help evaluate the ISO's proposal.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

The ISO states that as of January 1, 1998, the ISO will operate an electronic network or WEnet (Western Energy Network)

120/ See, July 30 Order, 80 FERC at 61,428-61,430.

121/ Id. at 61,433-35.

that will facilitate communications and data exchange among the

ISO, Market Participants and the public. The ISO states that the WEnet will comport with Order No. 889 in the context of California's market design and open access transmission proposal.

Commission Response

In Order No. 889, the Commission required public utilities that own, control, or operate facilities used for the transmission of electric energy in interstate commerce to create or participate in an Internet-based Open Access Same-Time Information System (OASIS). 122/ The provisions of Order No. 889 (the OASIS Final Rule) are intended to ensure that transmission customers have access to transmission information, through electronic means, that will enable them to obtain comparable, open access transmission service on a non-discriminatory basis. While we are satisfied that WEnet will meet the transmission information requirements of WEPEX Market Participants, in two important respects WEnet does not comply with the requirements of Order No. 889.

First, OASIS is designed to provide information about and accomplish the electronic reservation of transmission services offered under the Order No. 888 pro forma tariff, including Firm and Non-Firm Point-to-Point Transmission Services. In contrast, WEnet is designed to accomplish, among other functions, the electronic scheduling of energy transactions on a day-ahead and hourly basis, as provided in the ISO Tariff. Neither the ISO Tariff nor WEnet currently provides for the electronic reservation of transmission service for periods longer than one day. The Commission has ordered the ISO to file, by June 30, 1998, a plan to make available transmission rights on or before January 1, 1999. 123/

Second, in Order No. 889, the Commission required that each public utility s OASIS site be available on the Internet and that all information be provided in a uniform manner subject to a common set of communication standards and protocols. 124/ To the extent that the ISO's WEnet computer communication system is not compatible with the OASIS standards and protocols used by other transmission providers, the movement of power across the interstate transmission grid may be inhibited rather than enhanced.

The Commission will grant waiver of its OASIS requirements on a interim basis because the proposed WEnet meets the current needs of WEPEX Market

122/ Open Access Same-Time Information System and Standards of Conduct, F Rule, Order No. 889, FERC Stats. & Regs. □ 31,035, 61 FR 21,737 (199 order on reh'g, Order No. 889-A, FERC Stats. & Regs. □ 31,049, 62 FR 12,484 (1997) reh'g pending.

123/ July 30 Order, 80 FERC at 61,427.

124/ Order No. 889, FERC Stats. & Regs. □ 31,035 at 31,586.

Participants, including the ISO's transmission customers. However, we will require the
ISO to comply with the Commission's OASIS requirements and the associated Standards and Communication Protocols when it implements its transmission rights proposal in compliance with our July 30 Order. Also, in Order No. 889,

the Commission requested the industry to incorporate standards for electronic scheduling on OASIS in its report to the Commission on OASIS Phase II. 125/ We encourage the ISO as it gains operational experience with electronic scheduling to participate in these industry discussions. We expect the ISO to comply with OASIS Phase II requirements adopted by the Commission.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

The ISO states that it will be a member of the WSCC, WRTA and any other RTG and will participate actively in their planning and operating practices. Moreover, the ISO states that under the Transmission Control Agreement, the ISO is required to become a member of the WSCC in its capacity as control area operator. The ISO also states that, as the control area operator for the ISO Controlled Grid, the ISO will enter into appropriate arrangements with other control area operators in order to satisfy WSCC and NERC operating guidelines and reliability criteria. 126/ The ISO anticipates that it will enter into and file with the Commission interconnection agreements with all neighboring control areas by November 1, 1997.

Commission Response

As the control area operator, the ISO has committed to assume the responsibilities of PG&E's, SDG&E's and SoCal Edison s current interconnection agreements, in an effort to comply with ISO Principle No. 10. The ISO has indicated that it is currently negotiating new interconnection agreements with all neighboring control areas, and intends to file the agreements prior to the ISO Operation Date. We find that the ISO's proposal, including its commitment to negotiate and timely file interconnection agreements with all neighboring control areas, will adequately satisfy ISO Principle No. 10.

11. An ISO should establish an ADR process to resolve disputes in the first instance.

The ISO and PX initially proposed a "baseball" type ADR procedure, whereby each party submits its best single offer and the arbitration panel accepts one of the parties proposals. The ISO/PX stated that this type of arbitration procedure would engender reasonable settlement proposals from the interested

125/ Order No. 889, FERC Stats. & Regs. □ 31,035 at 31,628.

126/ March 31, 1997, Phase II filing, ISO Appendix 6 at 14.

parties since unreasonable proposals would be rejected by the arbitration panel. The ISO/PX stated that the proposed ADR procedure was based on the ADR procedure accepted by the Commission in the WRTA Agreement.

Our November 26 Order in this proceeding directed the ISO to incorporate in the Phase II filing an ADR proposal more similar to that contained in the WRTA Agreement. Specifically, we stated that the ADR process outlined in the WRTA Agreement provides the

arbiter more discretion in determining whether the parties' best offers are consistent with then-applicable Commission standards and policies and we directed the ISO/PX to incorporate in the Phase II ADR proposal the additional flexibility provided arbiters under the WRTA ADR procedure. 127/

The Phase II Filing

The Phase II filing proposes an ADR process that includes two options for resolving disputes: 1) the parties may request that the arbiter fashion an appropriate remedy, or 2) the parties may request to conduct the arbitration "baseball" style.

Contested Issues Identified by the ISO/PX

SoCal Edison contends that ISO Tariff Section 13.3.14 and PX Tariff Section 7.3.14 provide for the discriminatory treatment of arbitration costs and should be eliminated. 128/

TANC, NCPA, LADWP, Southern Cities/Azusa and Banning contend that Section 5.3 of the Transmission Owner Tariff improperly subjects the Access Charges of Local Publicly Owned Electric Utilities to the ISO ADR procedures. The Parties state that unlike Section 7.1.1 of the ISO Tariff, Section 5.3 of the Transmission Owner Tariff fails to recognize that rates offered by Local Publicly Owned Electric Utilities are matters within the exclusive jurisdiction of the Local Regulatory Authority. 129/ Moreover, these parties state that Section 5.3 of the Transmission Owner Tariff improperly provides that the access charges including any applicable Transmission Revenue Balancing

127/ November 26 Order, 77 FERC at 61,820.

128/ SoCal Edison at 29.

129/ TANC at 111-112; NCPA at 24-25; MID at 15; LADWP at 34,62; and South Cities/Azusa at Banning at 9.

Account of Local Publicly Owned Electric Utilities will be subject to the ISO ADR procedures. 130/

Southern Cities/Azusa and Banning contend that ISO Tariff Section 13.24 should be changed to provide that mediators and representatives should have authority to "negotiate" rather than "settle." Southern Cities/Azusa and Banning also contend that ISO Tariff Section 13.3.14 should be amended to provide that a party should not have to pay the cost of a non-neutral arbitrator picked unilaterally by an opposing party. Southern Cities/Azusa and Banning contend that ISO Tariff Section 13.4.2 should be amended to allow a party to submit relevant information on appeal that was not available at the time of arbitration. 131/ Southern

Cities/Azusa and Banning contend that ISO Tariff Section 13.4.3.1 should be amended to provide a 30-day period (rather than a 14-day period) for filing a notice of appeal. 132/

June 23, 1997 ISO/PX Reply Comments

In response to SoCal Edison's concerns with regard to arbitration costs, the ISO/PX states that Sections 13.3.14 of the ISO Tariff and 7.3.14 of the PX Tariff were the product of negotiation among the participants in this proceeding. The ISO urges the Commission to find the amended Section 13.3.14 and Section 7.3.14 are appropriate provisions within the ADR rules. According to the ISO/PX, those sections ensure that important public interests can be heard in ADR proceedings under appropriate safeguards, guaranteeing that right is indeed important, the need for relief from litigation costs is established and justice is served by the relief. 133/

In response to parties' concerns regarding the inconsistency between the ISO and Transmission Owner Tariffs, the ISO/PX agrees that the relevant sections of the ISO Tariff and Transmission Owner Tariff are inconsistent. The ISO/PX believes that Section 7.1.1 of the ISO Tariff accurately reflects the fact that rates offered by the Local Publicly Owned Electric Utilities are matters within the jurisdiction of the Local Regulatory Authority. Section 5.3 of the Transmission Owner Tariff should be changed to be consistent with Section 7.1.1 of the ISO Tariff. However, the ISO/PX also believes that those who feel they have been aggrieved by the Access Charges set by Local Regulatory

130/ Id.

131/ Southern Cities/Azusa and Banning at 13.

132/ Id.

133/ ISO/PX June 23, 1997 Reply Comments at 339.

Authorities should have some forum where their complaints can be heard by a disinterested voice. 134/

Accordingly, the ISO/PX states that at its meeting on June 17, 1997, the ISO Governing Board supported amending Section 7.1.1 of the ISO Tariff to provide that the ISO Governing Board will hear assertions that an Access Charge has been set so high by a Local Regulatory Authority that competition will be adversely affected. Since the ISO is not a regulatory agency with rate setting authority, the only relief that the ISO can offer is to request that the Local Regulatory Authority reconsider its decision.

In response to Southern Cities/Azusa and Banning's recommended revision to Section 13.24 of the ISO Tariff, the ISO/PX contends that the proposal would not work because mediation with representatives who lack authority to settle would

be non-productive. 135/ The ISO/PX opposes Southern Cities' proposed modification to Section 13.3.14 of the ISO Tariff, arguing that the cost of all arbitrators should be borne by all parties. The ISO/PX states that it would create an appearance of a conflict of interest for an arbitrator to be paid by only one side. 136/ The ISO/PX opposes Southern Cities' proposed modification to allow parties to introduce new evidence on appeal of an arbitration decision, as it would change the appeal into a trial de novo. The proposal would not expedite the decision making process and should be rejected. Finally, the ISO/PX opposes Southern Cities/Azusa and Banning's proposal to lengthen the time period to file an appeal because short time periods are necessary to make ADR expeditious.

September 2, 1997 Comments

DWR requests clarification of the scope of ADR and the standard of review of arbitration decisions. DWR argues that since the Commission has ADR procedures that govern upon filing of a complaint or petition, allowing such a filing without resorting to the ISO and PX ADR Procedures would not unduly delay or be unfair to any party, and would allow the Commission to supervise the process. DWR recommends that ISO Tariff Section 13.1.1 be modified (with similar changes to PX Tariff Section

134/ ISO/PX June 23, 1997 Reply Comments at 341.

135/ ISO/PX June 23, 1997 Reply Comments at 345.

136/ ISO/PX June 23, 1997 Reply Comments at 346.

7.1.1) to specify the rights of parties to file a petition with the Commission without resorting to ADR as follows: 137/

> "Except as limited below or otherwise as limited by law, the ISO ADR Procedures shall apply to all disputes between parties which arise under the ISO Documents except where the decision of the ISO is stated to be final. A party shall not be required to use the ISO ADR Procedures as a condition precedent to filing a complaint or petition with FERC. If such a filing is made, the provisions of Subpart F of the FERC Rules of Practice and Procedure shall apply.

DWR also argues that the standard of review of the arbitrator's decision is unclear. According to DWR, the standards of review contained in ISO Tariff Sections 13.4.1 and 13.4.2 and in PX Tariff Sections 7.4.1 and 7.4.2 need to be clear, consistent with existing law, and properly balance the need for finality with the need for fairness. DWR recommends that the provisions of California Code of Civil Procedure Section 1286.3, (which are similar to section 12 of the Uniform

Arbitration Act) should be expressly included in the ADR procedures. DWR also points out that the findings of fact underlying arbitration decisions should not be subject to judicial review, consistent with the law in California and most other jurisdictions. Rather, DWR argues, awards should only be vacated based on a clear legal error. 138/

SoCal Edison argues that an amendment to section 13.1.1 of the ISO Tariff, exempting from ADR ISO decisions stated in the provisions of the ISO Tariff to be final, was not also made to the PX tariff, due to an apparent oversight. SoCal Edison requests a comparable amendment to Section 7.1.1 of the PX Tariff. 139/

CMUA contends that the ISO has failed to amend Section 5.3 of the Transmission Owner Tariff, consistent with the amendments to ISO Tariff Section 7.1.1, although the ISO agreed to the change in its June 23 Reply Comments. CMUA states that the change is necessary to reflect the fact that rates offered by Local Publicly Owned Electric Utilities are matters within the jurisdiction of the Local Regulatory Authority. 140/

137/ DWR at 52.

138/ DWR at 53.

139/ SoCal Edison at 6-7.

140/ CMUA at 8-9; Southern Cities/Azusa and Banning at 16.

Commission Response

The ISO and PX's proposed ADR procedure is reasonable, complies with our Phase I directive, and satisfies ISO Principle No. 11.

We reject DWR's recommended changes to ISO Tariff Section 13.1.1 and PX Tariff Section 7.1.1. DWR recommends that the ADR provisions of the ISO and PX Tariffs specify the right of parties to file a petition with the Commission without resorting to the ISO or PX ADR Procedures. The Commission does not have the time or resources to address the myriad of potential issues that Parties may have. All Parties should utilize the ISO's and PX's ADR Procedures to resolve disputes before coming to the Commission. We also reject DWR's recommended changes to Section 13.4.1 and 13.4.2 of the ISO Tariff and Sections 7.4.1 and 7.4.2 of the PX Tariff. We find that the ISO/PX's proposed standard of review of an arbiters decision to be reasonable.

We accept SoCal Edison's proposed change to PX Tariff Section 7.1.1 to provide that PX decisions that are stated in the PX Tariff to be final are not subject to ADR. We direct the PX to make the revisions as proposed by SoCal Edison. 141/

Our review indicates that Sections 13.3.14 of the ISO Tariff

and 7.3.14 of the PX Tariff are reasonable as revised. Normally, the Arbitration Costs will be assigned to all parties in the dispute. It is only under limited circumstances (i.e., a demand for arbitration was made in bad faith) that the arbitrator has the discretion to allow the winning party not to incur Arbitration Costs. We believe this provision is reasonable. In the event the arbitrator's assignment of costs is disputed, no party is precluded from requesting Commission review of the issue.

With respect to concerns that certain provisions of the Transmission Owner Tariff are not consistent with the relevant ISO Tariff provisions, we find that while the individual Transmission Owner Tariffs are not the subject of this order, we agree with the intervenors that the references to the ISO ADR procedures should be eliminated. We agree that the rates for Publicly Owned Electric Utilities are subject to the jurisdiction of Local Regulatory Authorities.

In addition, we find that the ISO's proposed modifications to Section 7.1.1 of the ISO Tariff are acceptable. The modifications merely allow entities to petition the ISO to request that the appropriate Local Regulatory Authorities review

141/ SoCal Edison's September 2, 1997, Comments at 6-7.

Access Charges. We find this role of the ISO, as an independent entity, to be acceptable in evaluating ISO Controlled Grid rates.

For the reasons stated by the ISO, we reject Southern Cities/Azusa and Banning's proposed modifications to Sections 13.24 and 13.4.2 of the ISO Tariff. We note that Southern Cities/Azusa and Banning's September 2, 1997, comments do not address the ISO's reasoning. In addition, for the reasons stated by the ISO, we reject Southern Cities/Azusa and Banning's proposed modification to Section 13.3.14 of the ISO Tariff. Once again, we note that the Southern Cities' September 2, 1997, comments do not address the ISO's reasoning. Moreover, we note that the ISO's proposal is consistent with standard ADR practice.

With regard to Southern Cities/Azusa and Banning's recommendation to increase the time period to file an appeal, we agree with the ISO/PX that the ADR process should be made reasonably expeditious. The proposed 14-day period for filing a notice of appeal following an adverse decision is reasonable. We note that the Southern Cities' September 2, 1997, comments do not address the ISO's reasoning.

November 1, 1997 Operation Date

The ISO and PX request to commence certain operations on November 1, 1997. The operations that the ISO and PX propose to implement at that time are the acceptance and processing of applications from Market Participants who will be using the services of the corporations when they initiate market

operations. For example, the ISO proposes to begin accepting applications for the certification of Scheduling Coordinators and the PX will begin accepting applications for PX Participants. The ISO and PX will also begin the process of entering into necessary contractual agreements. Such agreements for the ISO include Scheduling Coordinator Agreements, Reliability Must-Run Agreements, operating agreements with adjoining control area operators and agreements with other entities participating in the market. The PX agreements include Participating Agreements and Meter Service Agreements. 142/ The ISO and PX are authorized to commence the above-described operations effective November 1, 1997, as requested.

III. Existing Contracts

The ISO proposes to provide parties with various options for joining and securing transmission service from the ISO. The ISO Tariff defines a Participating Transmission Owner as an entity that is a party to the Transmission Control Agreement which has placed its transmission assets and Entitlements under the ISO's Operational Control. Conversely, the ISO Tariff defines a Non-Participating Transmission Owner as a transmission owner that is

142/ August 15 Filing at 10.

not a party to the Transmission Control Agreement, or a holder of transmission service rights under an Existing Contract that is not a Participating Transmission Owner. The ISO defines Existing Contracts as contracts which grant transmission service rights in existence on the ISO Operations Date.

The ISO proposes to honor all transmission service rights and obligations under the Existing Contracts of Non-Participating Transmission Owners (Existing Rights). 143/ The ISO also proposes that Participating Transmission Owners attempt to negotiate changes to any Existing Contracts so that the scheduling and operating provisions of customers served under Existing Contracts are consistent with the ISO's scheduling and operational practices. The ISO states that this is necessary to minimize the parties' costs of administering the contracts while preserving their financial rights and obligations. To the extent the parties to an existing contract are unable to negotiate changes to the Existing Contract, the Participating Transmission Owner and the customer who holds the transmission service rights under the Existing Contract will work with the ISO to develop operational protocols which will permit existing contractual rights to be exercised. In order to conform to existing operational practices and maintain reliability, Section 2.4.3.1 of the ISO Tariff states that the developed protocols will be based on existing protocols and procedures.

Section 2.4.4.2.1 of the ISO Tariff provides that for a period of five years from the date the ISO begins operation, parties to existing transmission contracts that choose to become Participating Transmission Owners may, either immediately, or at any time during that five-year period: 1) choose to exercise all existing rights (Non-Converted Rights); or 2) convert those rights to ISO transmission rights whereby the Participating Transmission Owner will turn over operational control of its transmission Entitlements to the ISO in accordance with the ISO's scheduling, congestion management, curtailment and other operating protocols (Converted Rights). 144/ Under Section 2.4.4.2.1 of the ISO Tariff, PG&E, SoCal Edison and SDG&E will be deemed to have converted all transmission service rights that they may hold under

Existing Contracts to Converted Rights as of the ISO Operations Date. A Participating Transmission Owner, or a customer that has existing transmission service rights (i.e., entitlements) on a Participating Transmission Owner's system, that converts its rights will then receive all future transmission services under the ISO or Transmission Owner Tariffs. However, a party

143/ ISO Tariff Section 2.4.4.1.1.

144/ The ISO Tariff also provides that a party to an existing firm transmission contract that converts its rights will receive appropri recognition of its rights under the Self-Sufficiency Test. In addit that party will also receive Usage Charge and wheeling revenues associated with its capacity rights. Existing Rights and Non-Conver Rights holders will not be responsible for paying Usage Charges and not receive Usage Charge revenues related to those rights, nor will be entitled to an allocation of Wheeling Out or Wheeling Through

revenues. See, ISO Tariff Sections 2.4.4.3.1.3, 2.4.4.3.1.4., and 2.4.4.4.4.1.

receiving service under an existing contract will continue to pay the provider of service under the contract at the rates provided for in the existing contract. 145/ At the end of the five-year transition period, the ISO proposes that all parties that remain or become Participating Transmission Owners immediately convert their existing rights to ISO transmission service rights. All parties that become Participating Transmission Owners at any time after the five-year transition period ends must immediately convert their existing rights to ISO transmission service rights. 146/

All parties with Existing Rights and Non-Converted Rights are obligated to notify the ISO of the type of service provided under the relevant contract (i.e., firm, non-firm, or conditional firm) and any special operating instructions that ISO may need in order for the ISO to perform its duties. The ISO Tariff provides that the ISO will have no role in interpreting Existing Contracts and that the ADR provisions of the existing contract should be used to resolve disputes. The ISO Tariff also provides that to the extent there is a dispute between the parties to an existing agreement, the ISO will implement the Participating Transmission Owner's operating instructions until the dispute is resolved. 147/

The ISO Tariff provides that the ISO's scheduling protocols will accommodate the scheduling, curtailment, assignment and other provisions of transmission service under Existing Rights and Non-Converted Rights. However, the ISO proposes to limit the within-the-hour scheduling flexibility of Participating Transmission Owners with Non-Converted Rights. Section 2.4.4.4.3 of the ISO Tariff states in part that:

> Non-Converted Rights under Existing Contracts giving scheduling flexibility after the close of the ISO's Hour-Ahead scheduling process shall not be exercised by the holders of such rights [emphasis added].

The ISO Tariff states that where such Non-Converted Rights provide within-the-hour scheduling flexibility, the parties to the relevant contracts will negotiate to, "restore the balance of the benefits and burdens of the relevant Existing Contracts."

145/ Parties to Existing Contracts will also continue to pay for transmis losses and ancillary services under their Existing Contracts. To th extent there are any differences in the requirements associated with Existing Contracts and those under the ISO's rules and protocols, th ISO will establish a mechanism acceptable to the Transmission Owner roll any shortfall or surplus into the ISO rates applicable to that Transmission Owner.

146/ Conversely, parties to Existing Contracts that do not become a Participating Transmission Owner retain their existing rights for th term of their contracts.

147/ ISO Tariff Section 2.4.4.4.1.1.

Contested Issues Identified by the ISO/PX 148/

Western, TANC, and BPA contend that a Participating Transmission Owner should be able to continue its Existing Contract rights for the full contract period, including extensions, and that there should be no transition period after which the scheduling and curtailment rights under Existing Contracts must be converted. 149/

Modesto considers that a period of ten years should be used for the transition period to give more time for renegotiation and planning the conversion of the rights. 150/ By contrast, California Commission considers that a two-year period is more appropriate to align it with the period for development of the pricing methodology required by AB 1890. 151/

Numerous parties argue that the rights under Existing Contracts must be upheld in their entirety and that the ISO must administer Existing Contracts in accordance with the procedures and protocols developed by the parties to those Existing Contracts. 152/

TANC also contends that the request in the Commission's Phase 1 Order to list Existing Contracts and proposals for their treatment indicates that Existing Contracts should remain in force, except when unilaterally changed under section 205 of the FPA or by voluntary conversion. However, TANC claims that the underlying rights should remain unchanged. 153/

CCEM, California Commission, and EPMI contend that any retention of the Existing Contracts is discriminatory and unfair to other Market Participants. 154/ CCEM recommends the immediate conversion of existing rights to Converted Rights with any dispute being settled by the ISO ADR Procedures. 155/

The California Commission raises concerns with regard to the integration of the ISO's operational protocols and procedures and the disparate protocols and procedures associated with Existing Rights and Non-Converted Rights. The

148/ Issues identified in the August 15 filing as remaining in contention See Appendix I, Part 3.

149/ Western at 48, TANC at 27, DWR at 34-37, and BPA at 77.

150/ Modesto at 24-26.

151/ California Commission at 43.

152/ Turlock at 24; Oakland at 17; Destec at 4; TANC at 27; BPA at 77; NC at 21-22; San Francisco at 9; and Western at 46.

153/ TANC at 28.

154/ CCEM at 27; California Commission at 32-35; and EPMI at 10-11.

155/ CCEM at 28-29.

California Commission recommends that a technical conference be held on this issue. 156/

A number of parties contend that the holder of a capacity entitlement under an Existing Contract must be compensated by the ISO for the use of that capacity in the Hour-Ahead Market. 157/

TANC contends that the ISO ADR procedures should not be invoked in a dispute between the ISO and a Non-Participating Transmission Owner. TANC is concerned that the ISO's ADR procedures will apply whether or not both parties are Participating Transmission Owners and whether or not the Existing Rights have become Converted Rights. TANC contends that there is no justification for imposing the ISO ADR procedure on a party that has not subscribed to the ISO Tariff. 158/

A large number of parties raise concerns over the ISO Tariff provision which states that, in cases where there is a dispute, the ISO will follow the Participating Transmission Owners' operating instructions. TANC states that, at a minimum, a dispute over operating instructions should be handled as follows: (1) if the dispute is between the parties to an Existing Contract, the dispute should be resolved under the terms of the Existing Contract; and (2) if the dispute is between the Participating Transmission Owner and the ISO, the holder of the Existing Rights should be a party to the ISO dispute resolution procedure and the disputed instruction should not be implemented until the dispute is resolved. 159/

BPA is concerned that if the parties to an Existing Contract with Non-Converted Rights cannot agree to modifications, until the dispute is resolved, the operating instructions of the Participating Transmission Owner will be followed, which discriminates against the other party, especially if it is a Non-Participating Transmission Owner. 160/

BPA considers it inappropriate for the ISO to classify the failure to negotiate new terms as a dispute under the Existing Contract. BPA requests the Commission to remove this provision and to review each on a case-by-case basis. 161/

156/ California Commission at 68.

157/ DOE/OAK at 5; TANC at 43; and Western at 51.

158/ TANC at 46.

159/ Id. at 45-48.

160/ BPA at 83.

161/ BPA at 83-84.

TANC, SRP and BPA contend that a Scheduling Coordinator should not be able unilaterally to submit operating protocols for an Existing Contract for the ISO to follow without the concurrence of all parties to the contract. 162/

Numerous intervenors contend that the ISO should not be able to preclude the exercise of within-the-hour scheduling flexibility in Existing Contracts. 163/

June 23, 1997 ISO/PX Reply Comments

The ISO/PX state that their proposal for honoring Existing Contracts is a fair and workable solution, which balances the tension between the desired protection of valuable rights under Existing Contracts and the need for a completely unburdened ISO able to operate and control the system in a flexible manner.

The ISO/PX state that their proposal honors all Existing Contracts and provides, in compliance with the Commission's Phase I order, under Sections 2.4.3 and 2.4.4 of the ISO Tariff, a mechanism for parties to Existing Contracts to submit to the ISO the necessary operating instructions for Existing Contracts.

In response to the California Commission's concern that the independence of the ISO is threatened because operational control of Existing Contracts remains with Participating Transmission Owners, the ISO/PX state that, upon conversion under Section 2.4.4.3.1.1 of the ISO Tariff, the recipient of transmission service "shall turn over Operational Control of its transmission entitlement to the ISO." In addition, the ISO/PX state that during the five-year transition period when a Participating Transmission Owner can hold Non-Converted Rights, Sections 2.4.3.1 and 2.4.4.5. of the ISO Tariff provide for a process that will permit the ISO to easily follow the Existing Contracts' operating instructions.

With regard to intervenor arguments that the ISO should compensate entitlement holders for the use of their unused capacity, the ISO/PX state that this would only occur if the holder of the rights does not need the transmission capacity and does not, therefore, schedule its full allocation in the Hour-Ahead Market. The ISO/PX state that the many Steering Committee discussions on this matter did not include as an option compensation for unused capacity.

In addition, the PX/ISO state that under the ISO Tariff, entities which convert their rights are allowed to share in any Usage Charges or other revenues (e.g., TCCs) associated with the use of facilities to which they hold entitlement and that where rights have not been converted, the ISO will have

162/ TANC at 47; SRP at 15.

163/ Redding at 8-10; DOE/OAK at 5; NCPA at 18; Modesto at 11-14; CMUA at 27; TANC at 41-43; and LADWP at 25.

no mechanism to compensate existing entitlement holders. Moreover, the ISO/PX contend that unutilized capacity is analogous to non-firm transmission capacity and that the ISO does not provide non-firm service. The ISO/PX state that the ISO does not receive any additional revenues for the use of the released capacity unless there is congestion or there are wheeling transactions.

In response to intervenor concerns over the use of the ISO ADR procedure, the ISO/PX state that they agree with TANC and that if a dispute is between the parties to an Existing Contract, then clearly the dispute resolution procedure contained in the contract will apply. However, if the dispute is between a Non-Participating Transmission Owner and the ISO, the ISO/PX state that the ISO ADR Procedure, which is designed to provide a quick resolution, is available. In addition, the ISO/PX state that Section 2.4.4.5.4 relates to disputes between the ISO and the Participating Transmission Owner and that this section states that "[t]he transmission rights holder(s) under the Existing Contract shall have standing to participate in the ISO ADR Procedure." Therefore, the ISO/PX conclude, the ISO ADR Procedures can be invoked by all the necessary parties.

The ISO/PX state that as for disputes between Participating Transmission Owners and the ISO, these are governed under Section 13 of the ISO Tariff. Finally, the ISO/PX state that the changes TANC proposes are not acceptable because they could result in there being no clear procedures for the ISO to follow when the meaning of contract procedures is contested. Moreover, TANC's request for a case-by-case review by the Commission is not practical because of the sheer number of Existing Contracts involved.

In response to BPA s recommendation that Existing Contract terms not be immediately modified to conform to ISO protocols and procedures but that parties be allowed a reasonable time to modify them, the ISO/PX state that Section 2.4.4.4.2 of the ISO Tariff provides that the ISO's scheduling protocols will accommodate both Existing Rights and Non-Converted Rights during the transition period.

Specifically, the ISO/PX state that Section 2.4.3.1 of the ISO Tariff requires the Participating Transmission Owner, the holder of the rights and the ISO to work together to develop these protocols. The ISO/PX emphasize that the ISO cannot get involved in contract interpretation and must be given the operating protocols that the parties want to implement. The ISO/PX argue that in disputes regarding the operating instructions for Existing Contracts the rights-holder will be protected in two ways. The ISO/PX contend that the ISO can refuse the Schedule if the principles, rules and protocols are not adhered to under Section 2.4.3.2 or the rights holder can pursue its rights and seek redress from the Participating Transmission Owner.

With respect to intervenor arguments that rights holders should be compensated for the loss of scheduling flexibility, the ISO/PX state that this is certainly a possible outcome of the renegotiation called for under the ISO Tariff. The ISO/PX state that there was a debate on this issue at the ISO Governing Board meeting on June 17, 1997, and it was agreed that the ISO should support and encourage the efforts of the parties to negotiate an

elimination of such rights, but no other changes to the ISO Tariff should be made to deal with this issue.

September 2, 1997 Comments

TANC raises concerns that the use by the ISO of an entity's unused transmission capacity will jeopardize the tax exempt status of the debt borne by entities such as TANC. 164/ TANC states that until it obtains a private letter ruling from the IRS or an unqualified opinion from bond counsel, the ISO's use of TANC's unused transmission capacity could trigger the loss of its tax exemption.

Numerous parties raise concerns that Transmission Control Agreement Section 4.4.3 will prohibit parties from exercising certain rights under their existing contractual arrangements. 165/ Specifically, they contend that Section 4.4.3 of the Transmission Control Agreement will prevent them from: 1) exercising rights to increasing amounts of transmission service (for load growth); 2) changing points of delivery and receipt; and 3) operating or integrating resources to serve load. PG&E, in fact, requests guidance from the Commission as to how it should proceed between now and the start-up date of the ISO, with respect to requests for new or increased service under existing agreements and its Open-Access Transmission Tariff. 166/

DWR asserts that the ISO Tariff and the Transmission Control Agreement should be revised to accommodate a right of first refusal for parties to Existing Contracts. 167/ DWR states that Order No. 888 provided that existing transmission customers, upon the expiration of their contracts, have the right to continue to take service from their existing transmission provider. DWR states that existing contract holders that exercise the right of first refusal would pay the ISO's access charge and receive usage charges or other financial rights. In addition, DWR states that the right of first refusal should apply to the ISO's congestion pricing proposal. DWR recommends that the ISO Tariff be changed to require notification to existing contract holders of the highest adjustment bid, and the right to match that bid in order to receive service over a congested path.

San Francisco argues that all elements of the ISO Tariff and the Transmission Control Agreement must clearly distinguish between existing contract rights and capacity subject to the control of the ISO. Contract

164/ TANC at 67-74.

165/ Contract Entitlement Holders (BPA, CMUA, Destec, and Western) at 7-1 Southern Cities/Azusa and Banning at 18; TANC at 141-145; San Franc at 5-6; NCPA at 30-41; SMUD at 28-32; Santa Clara and Palo Alto at 2 28.

166/ PG&E at 3-8.

167/ DWR at 11-15.

Entitlement Holders request confirmation that the ISO will accommodate existing agreements in its operational protocols, to the extent that it assumes the responsibility of existing control area operators. 168/

San Francisco and Southern Cities/Azusa and Banning argue that the ISO's proposed amendment to ISO Tariff Section 2.4.4.1.2 should be rejected because it does not adequately clarify that existing contract rights holders will not be liable for access charges. According to San Francisco the provision presumes that power delivered on behalf of entities that are Market Participants, by virtue of their existing contractual rights, is also subject to the Access Charge. 169/ Destec requests an exemption from access charges applicable to Existing Contracts with rates that overlap with the transmission rates under the ISO Tariff. Destec opposes the approach taken in the August 15 Filing of allowing for negotiations to Existing Contracts to avoid duplicative charges. Destec states that the revision conflicts with ISO Tariff Section 2.4.4.4.4.3, which requires that rates under Existing Contracts remain in place, and requires the cooperation of the transmission provider to avoid double collection of rates. 170/

PG&E contends that ISO Tariff Section 2.4.4.1.2 is unclear because the term "duplicative" is not defined. PG&E is concerned that some existing rights holders may use the change to avoid paying the ISO rate, to the detriment of the Transmission Owner's own ratepayers or shareholders. PG&E recommends deleting the new language. 171/

In general, DWR contends that ISO service to existing contract holders should be no more costly or difficult to obtain or use. According to DWR, the sum of the parts as restructured should be neither more costly nor more burdensome to access than the whole.

CCC contends that the August 15 Filing continues to contain provisions that will interfere with existing contractual arrangements between QFs and IOUs. For example, under ISO Tariff Section 2.3.3 the ISO may coordinate and approve scheduled maintenance outages for QFs, and under ISO Tariff Section 5.1.1 participating generators (including QFs) must operate their facilities in accordance with, among other things, the operating requirements for normal and emergency operating conditions under section 2.3. According to CCC, the duration and timing of scheduled outages under QF contracts is essential to allow QFs to meet their obligations to provide power to the IOUs during designated peak periods and to ensure that the IOUs meet their payment obligations to QFs. CCC also argues that ISO Tariff Section 5.5.1 would allow the ISO to interfere with QFs maintenance plans, and that ISO Tariff Section 10.2.2 would allow the ISO to impose metering requirements that are

168/ San Francisco at 5-6; Contract Entitlement Holders at 7-10.

169/ San Francisco at 6; Southern Cities/Azusa and Banning at 12.

170/ Destec at 2-3. See also, Redding at 22.

171/ PG&E at 11.

potentially inconsistent with QF contracts. CCC recommends clarifications to the Tariff to protect existing contract rights and define the relationship among the IOUs, QFs and the ISO. 172/

CMUA contends that the definition of Existing Contract excludes certain integration, interconnection, and other agreements, which also must be honored and accommodated. 173/

Southern Cities/Azusa and Banning propose that ISO Tariff Section 2.4.4.2.1 be modified to clarify that a Transmission Owner can continue to be a Participating Transmission Owner even if it is unable to convert any contractual rights due to a refusal by another party to the contract to agree to a conversion.

Southern Cities/Azusa and Banning propose amendment of ISO Tariff Section 5.6.1 to clarify that the ISO s rights to control Generating Units during a System Emergency or conditions threatening a System Emergency are subject to Existing Contracts that define the rights of the Participating Generator that owns or controls the Generating Unit.

DWR requests that the Commission clarify that all existing contract rights not specifically discussed within the ISO Tariff must be preserved, for both Participating Transmission Owner s and non-Participating Transmission Owner s, including the Order No. 888 right of first refusal for contract extensions. 174/ According to DWR, any Existing Contract provisions that have not been specifically identified by the ISO or PX as conflicting with their protocols and operating practices should be honored for their full term. DWR proposes amendment of section 2.4.4.3.2 of the ISO Tariff to provide: 175/

> The recipient of transmission service under an Existing Contract that has converted its rights to ISO transmission service may have other rights not specifically identified within Section 2.4.4.3. Those rights shall be continued to be honored. Such rights Existing Contract (sic) may also need to be changed if such change is necessary to operate within the ISO s Operating Procedures. . ..

DWR contends that the Transmission Control Agreement should accommodate first refusal rights for renewal of a contract following its expiration. DWR

172/ CCC at 3-8.

173/ CMUA at 24-25.

174/ See Order No. 888, FERC Stats. & Regs. □31,036 at 31,665 (which provid right of first refusal to customers under existing firm transmission contracts to extend the contract at a price that others are willing pay).

175/ DWR at 10.

believes that Existing Contract rights to increase service or extend the term, change points of delivery and receipt (in the case of non-participants in the ISO) and to operate or integrate resources with loads, are all Existing

Contract rights that must be honored, consistent with Order No. 888 and the California Restructuring Legislation.

DWR supports the proposed five-year transition period, after which ISO Participants scheduling and curtailment rights would be converted to ISO protocols (contrary to assertions by the ISO).

DWR contends that the ISO Tariff should afford existing contract holders who become Participating Transmission Owners access to the entire ISO grid, rather than access limited to a particular contract path or network entitlement. This is one of the primary incentives for existing contract holders to join the ISO, according to DWR, and it would occur regardless of timing of conversion of firm transmission rights to financial rights. Therefore, DWR recommends a the following language be added to section 2.4.4.2 of the ISO tariff: 176/

> Parties who are entitled to transmission service under Existing Contracts and who choose to become Participating Transmission Owner s will be entitled to network service to the entire ISO grid, notwithstanding that rights under Existing Contracts may be limited to specific paths or limited network Entitlements.

CMUA contends that ISO Tariff Section 2.4.4.4.3 must retain rights of Existing Contract holders with Non-Converted Rights to schedule transmission Entitlements closer to real time (after the close of the Hour-Ahead scheduling process), or provide for compensation if these rights are to be eliminated. According to CMUA, the provision to negotiate to restore the balance of the benefits and burdens is insufficient. 177/

DWR supports amended section 2.4.4.3.1.4 of the ISO Tariff, which entitles existing rights holders usage charge revenues for capacity and wheeling revenues credits while the capacity is available under the existing agreements, and opposes proposals to abrogate existing contract rights at the outset, as violating Order No. 888, the Restructuring Legislation, and the California Commission Decision.

DWR requests that the ISO Tariff be clarified to ensure that existing contract rights holders receive a direct payment of usage charge revenues. According to DWR, Section 2.4.4.3.1.4 provides for Existing Contract holders to receive usage charge revenues. However, DWR notes that Section 7.3.1.6 provides for net Usage Charge revenues to be credited to the Transmission

176/ DWR at 8.

177/ CMUA at 21-24. See also, Santa Clara and Palo Alto at 22; M-S-R at 21- 24; Redding at 11-12; and Modesto at 10-15.

Revenue Balancing Account (TRBA) of the Participating Transmission Owner who own the Inter-Zonal Interfaces, and does not explain how such revenues wold be allocated back to transmission rights holders. DWR proposes to credit only residual Usage Charge revenues to the TRBA, after direct disbursement of usage Charge revenues to Existing Contract rights holders.

DWR argues that the ISO congestion pricing proposal does not provide for

Existing Contract rights holders to be notified or allowed to match the incremental Adjustment Bids, to preserve their firm entitlement rights. DWR proposes modification of the ISO tariff to require such notification and opportunity to match adjustment bids. 178/

PG&E requests guidance as to how it should proceed between now and January 1, 1998 with respect to requests for new or increased service under existing agreements and PG&E s Open Access Tariff (OAT) that would commit existing capacity for many years beyond the start of ISO operation. According to PG&E, recent requests for service, if agreed to, would lock up virtually all available transmission capacity, leaving little to transfer to ISO operational control on January 1, 1998. 179/ PG&E states that honoring existing contracts should not be expanded to give existing contract holders preference over future users that they do not currently have under their contracts. PG&E contends that upon execution of the Transmission Control Agreement, it will have fully committed its transmission system to the ISO. At that point, PG&E states, it will no longer have available capacity on the ISO Grid facilities it owns for request for new of additional service by such flexible contract holders. PG&E also requests clarification regarding the status of its OAT once ISO operations commence. PG&E suggests, as it has in the past, that its OAT should be deemed superseded by the ISO Tariff. 180/

Numerous parties object to PG&E s proposed definition of new encumbrance, which would freeze the rights of existing transmission contract holders to the particular amount of transmission service currently being used, and deny such contract holders the rights for future growth and change for which they contracted. 181/ Western also notes that ISO Tariff Section 2.4.4.1.1 requires that the rights of non-Participating Transmission Owners under Existing Contracts, including rates, terms and conditions as they may change from time to time under the terms of the contracts, must continue to be honored. Similarly, Western, Oakland, Contract Entitlement Holders and San

178/ DWR at 14.

179/ PG&E states that the problem occurs with respect to the contracts th have flexible capacity and receipt and delivery point commitments, w can vary over time, as well as its OAT.

180/ PG&E at 3-8.

181/ Western at 32-37; IEP at 7-8; Destec at 3-6; San Francisco at 5-6; Oakland at 6; Santa Clara and Palo Alto, Southern Cities and Azusa and Banning at 18; and Contract Entitlement Holders at 7-10.

Francisco request clarification in the ISO Tariff that exercising rights under Existing Contracts will not be considered a "new Encumbrance" and will not require ISO approval under section 4.4.3 of the Transmission Control Agreement. 182/

SoCal Edison opposes the ISO and PX proposed revisions to Section 2.4.4.1.2 of the ISO Tariff, which would now allow renegotiation of rate terms as well as scheduling and operating provisions to align with the ISO Tariffs. SoCal Edison contends that the new language encourages transmission providers to provide service under Existing Contracts for free and is beyond the scope of the ISO Tariff. According to SoCal Edison, rate terms are solely within

the purview of the parties to the contracts. Also, SoCal Edison states that the renegotiations must be made in accordance with the standards and procedures of the contracts themselves, consistent with ISO Tariff Section 2.4.4.5.2. SoCal Edison also complains that Section 2.4.4.1.2 is ambiguous, and would abrogate existing rate terms rather than honor them. 183/

September 16, 1997 Comments

Western, Turlock, SMUD, and TANC oppose PG&E's argument that commitments for new or additional transmission under Existing Contracts constitutes a new encumbrance. Western, Turlock and SMUD contend that PG&E has mischaracterized their Existing Agreements as "flexible" or as "available" contracts, under which it should allocate service on a first-come, first-served basis with no commitment to reserve capacity for yet unmade future requests. 184/ As to PG&E's argument that "flexible contracts" are "as available contracts" TANC contends that this argument is true only as to Coordination Service or non-Firm Service, but that it does not apply to Reserved Transmission Service. 185/ Similarly, SMUD disputes PG&E's claim that honoring Existing Contacts would involve expansion of the contract holders' rights to provide a preference over future uses that they do not have, since they merely want their existing bargained-for agreements for firm transmission to be recognized and enforced. 186/

SMUD recommends that the Commission accept the solution agreed to by the stakeholders, as reflected in ISO Tariff Section 2.4.4.5.2. To clarify this agreement, SMUD recommends amendment of Transmission Control Agreement Section

182/ Id.

183/ SoCal Edison also states that its proposed revenue requirement submi in Docket No. ER97-2358-000 was predicated on expected revenues from Existing Contracts, in reliance on prior rules.

184/ Western September 16 Comments at 4-6; Turlock September 16 Comments 4-6, SMUD September 16 Comments at 4-5.

185/ TANC September 16 Comments at 10-15.

186/ SMUD September 16 Comments at 2-3.

4.4.3, to specify that "the exercise of rights and obligations in Existing Contracts shall not be deemed the creation of a new Encumbrance or the expansion of an existing Encumbrance." 187/

Metropolitan and TANC oppose the California Commission's proposal to immediately terminate the Existing Contract rights of Participating Transmission Owners and to phase out Existing Contract rights within two years. 188/ Metropolitan and TANC contend that the California Commission's proposal is unsupported, untenable, and inconsistent with the California Legislature's mandate in the Restructuring Legislation to honor Existing Contracts. 189/ Metropolitan argues that Existing Contracts are an integral part of the long-term plans and operations of many publicly-owned utilities. Eliminating those arrangements is not necessary to ensure the independence of the ISO, and would deny the benefit of intricate, long-term arrangements to the parties that open access was intended to benefit, according to

Metropolitan. 190/

Commission Response

In Order No. 888 the Commission concluded that it would be inappropriate to order generic abrogation of existing requirements and transmission contracts. The Commission found that although the electric utility industry was undergoing a dramatic transition to a competitive market, the changes did not warrant a generic abrogation of existing contracts. 191/ Similar circumstances exist here. Although the California energy market is undergoing a monumental change, we believe that it is inappropriate and unnecessary to abrogate existing transmission contracts in order to implement the proposed restructuring of California's electric power industry. We disagree with CCEM, the California Commission, and EPMI that the retention of existing contractual rights is discriminatory and unfair to other market participants. While we agree with the California Commission that it may be difficult for the ISO to accommodate the varied operational protocols and procedures of Existing Contracts, we view this as an unavoidable transitional problem. We believe that the temporary problem of accommodating the scheduling and operating practices of Existing Contracts under the ISO's rules and protocols is outweighed by considerations of not upsetting the benefits and obligations of Existing Contracts, which were established over many years. 192/

187/ SMUD September 16 Comments at 9-10.

188/ See California Commission's September 2, 1997 Comments at 22-23.

189/ Metropolitan September 16 Comments; TANC September 16 Comments at 6-

190/ Metropolitan September 16 Comments at 3-6.

191/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,663.

192/ However, this decision does not affect any rights that parties may h
(continued...)

Accordingly, we accept the ISO's proposal to honor all Existing Contracts of Non-Participating Transmission Owners. Such contracts would include existing transmission contracts, interconnection agreements, and all other contracts that pertain to the use of a Non-Participating Transmission Owner's transmission system. We also conclude that it is in the public interest to accept the ISO's proposed five-year transition period for Participating Transmission Owners to convert their existing contractual rights to ISO rights. That is, we agree with the ISO that those entities that decide to participate and become a member of the ISO should be obligated to conform their existing transmission contracts to the operating rules and protocols of the ISO. We agree, however, that to the extent a Participating Transmission Owner wishes to exercise its Non-Converted Rights during the interim period, the ISO should honor those rights as detailed in the relevant transmission and/or interconnection agreements. We disagree with Modesto that the transition period should be ten years. 193/ The ISO's proposed five-year transition period is reasonable and provides all entities ample opportunity to explore and weigh the costs and benefits of participating in the ISO. 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.

Scheduling Flexibility

We reject the ISO's proposal to deny Non-Converted Rights holders the opportunity to exercise their within-the-hour scheduling rights under Existing Contracts. Parties to Existing Contracts that have such scheduling flexibility should be permitted to exercise those rights until they either convert their existing rights to ISO rights or the five-year transition period ends. A number of parties have raised concerns that without their existing scheduling flexibility, they will be unable to efficiently integrate their resources and respond to fluctuations in load. The ISO has provided no technical reason that it will not be able to accommodate these scheduling practices. Moreover, the ISO has already committed to honor the Existing Contracts of Non-Participating Transmission Owners, who will retain any scheduling rights that are presently in their Existing Contracts. We therefore direct the ISO to revise Section 2.4.4.4.3 of the ISO Tariff to remove this provision.

Compensation for Unused Capacity

192/ (...continued)
to seek case-by-case modification of Existing Contracts under sectio 205 or 206 of the Federal Power Act.

193/ Modesto June 6, 1997, Comments at 24.

We disagree with DOE/OAK, TANC, Western and others who argue that the ISO should compensate those entities with existing capacity Entitlements for the use of that capacity in the hour-ahead market. 194/ Traditionally, if a customer did not utilize all of its transmission entitlement, the transmission provider and other third-party customers could utilize that capacity on a non-firm basis. In this instance, the ISO does not provide traditional non-firm transmission service. The ISO will only receive revenues for that capacity if there are Wheeling transactions that utilize the capacity or through Usage Charges. To the extent a rights holder has converted its rights to ISO rights, then it would receive its share of any Wheeling and Usage Charge revenues that arise from the use of its unused transmission entitlement. However, if a rights holder does not convert its rights over to the ISO, then that entity will not be entitled to any such Wheeling or Usage Charge revenues, to the extent that its Non-Converted Rights do not provide for such compensation.

TANC raises concerns that the ISO s use of an entity s unused capacity may jeopardize its tax-exempt debt. We recognize the importance of this issue to TANC and other entities that have tax-exempt debt. Section 2.1.3 of the ISO Tariff recognizes TANC's concerns by restricting the ISO from in any way violating the tax-exempt status. This section provides for the cooperation of tax exempt participants and the ISO to establish procedures to meet this objective and to make changes as necessary from time to time. In its

September 16, 1997 Comments, the ISO and PX agreed to work with LADWP to determine appropriate language dealing with the tax-exempt status issue to include in the ISO Tariff and Transmission Control Agreement compliance filing. We encourage TANC and all other interest parties to participate in these discussions. However, until TANC and others secure a ruling from the IRS with regard to their participation in the ISO and the status of their tax-exempt debt, it is premature for the Commission to rule on the merits of specific ISO Tariff provisions and their impact a party's tax-exempt status.

Encumbrances

Section 4.4.3 of the Transmission Control Agreement states that:

> [n]o Participating Transmission Owner shall create any new encumbrance or (except as permitted by Sections 2.4.3 and 2.4.4 of the ISO Tariff) extend the term of an existing Encumbrance over any lines or associated facilities forming part of its transmission network (as determined in accordance with Section 4.1.1) without the ISO's prior written consent.

In response to concerns raised by many parties that Transmission Control Agreement Section 4.4.3 will preclude them from exercising certain rights under Existing Contracts, and to provide guidance requested by PG&E, the Commission finds that parties to Existing Contracts should be able to exercise their rights under those Existing Contracts. To the extent that an existing

194/ DOE/OAK June 6, 1997, Comments of 5; TANC at 43; and Western at 51.

contract provides for the right to schedule additional transmission service to accommodate load growth, the ISO must accommodate such increased schedules. In addition, to the extent a party has the right to change receipt and delivery points, or to adjust its schedules in order to economically integrate its resources and load, that party should retain those abilities. Therefore, we direct the ISO to modify Section 4.4.3 of the Transmission Control Agreement to clarify that the exercise of rights under Existing Contracts will not be considered a "new encumbrance."

With respect to PG&E's request for guidance concerning requests for new or increased service under its Open Access Tariff, we find that it is necessary to limit future requests for service in order to minimize the ISO's burden of administering these existing services and in order to expedite the transition to service under the ISO's newly established operating rules and protocols. Accordingly, we hereby amend the Companies' Open Access Tariffs 195/ to incorporate provisions that honor all transmission service agreements executed before the date of this order. With respect to all future requests for service, we direct the Companies to limit the term of all transmission service agreements so that service does not extend beyond the ISO Operations Date. 196/ In light of the above modifications, we reject PG&E's contention that upon executing the Transmission Control Agreement, it will no longer be obligated to provide additional transmission services.

Right of First Refusal

We disagree with DWR that existing contract holders should have the

right of first refusal with respect to service under the ISO Tariff. As initially proposed, the ISO Tariff does not provide for the long-term reservation of transmission capacity. As proposed, the ISO will attempt to accommodate the transmission service schedules of participants on a daily basis. To the extent that the ISO receives more requests for service than it can accommodate, it will attempt to efficiently ration constrained transmission capacity through congestion pricing. The ISO's proposal to

195/ The Open Access Tariffs were filed by PG&E in Docket No. OA96-28-000 SoCal Edison in Docket No. OA96-76-000, et al. and SDG&E in Docket N OA96-139-000.

196/ Section 2.2 (Reservation Priority For Existing Service Customers) of Companies' currently effective Open Access Transmission Tariffs shal replaced in its entirety by the following:

2.2 California Independent System Operator Corporation Operations Date: Service Agreements, irrespective of the term, executed prior to the date of the Commission's order in Docket No. EC96 001, et al., will be honored by the Transmission Provider for agreed upon term. Service Agreements executed on or after the date of the Commission's order in Docket No. EC96-19-001, et a are limited to a term of no greater than the California Independent System Operator Corporation grid operations date.

schedule transmission on a day-ahead and hour-ahead basis is not compatible with the long-term reservation of discrete physical transmission rights. Moreover, in Order No. 888, the Commission was addressing the tension that existed for the use of available transmission capacity between native load, existing third-party contracts, and new third-party transmission customers. 197/ That tension does not exist here.

We find that the ISO's congestion pricing proposal is significantly different from the circumstances we considered in Order No. 888. In Order No. 888 we were addressing the firm reservation of physical transmission rights whereas the ISO's congestion management proposal is applicable to the efficient rationing of constrained transmission capacity on an hourly basis. Therefore we find DWR's assertion that the right of first refusal should extend to the ISO congestion pricing proposal to be inapposite. We recognize, however, that existing customers may wish to assert a right of first refusal with respect to the ISO transmission rights proposal that will be implemented as of January 1, 1999, pursuant to our July 30 Order. 198/ We intend to revisit this issue when the ISO submits its transmission rights proposal in June 1998.

Submission of Operating Orders

As noted above, ISO Tariff Section 2.4.4.4.1.1. states:

The ISO shall have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any operating instructions that will be submitted to the ISO. 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 Transmission Owner's operating instructions.

A number of parties argue that the provision that the ISO implement the Participating Transmission Owner s operating instructions pertaining to Existing Contracts is unfair and unreasonable. 199/ TANC argues that, at a minimum, disputed operating instructions should not be implemented until the dispute is resolved. We disagree. We find that it is reasonable for the ISO to rely on the operating instructions of the Participating Transmission Owner. The Participating Transmission Owner is the entity most familiar with performing the operating instructions on a day-to-day basis under the existing

197/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,694.

198/ July 30 Order, at 61,427-61,428.

199/ See, e.g., TANC September 2, 1997, Comments at 75-80; BPA at 83.

contract. In addition, we find TANC's recommendation to not implement the disputed instructions until the dispute is resolved to be unworkable. The ISO must have full and complete information, including all necessary operating instructions; to the extent it does not, the ISO should reject any schedule submitted under that contract. As TANC notes, this would only result in damaging the rights holders interests. 200/ Finally, we agree with parties that Scheduling Coordinators should not be able to submit operating orders to the ISO for Existing Contracts without the prior approval of the parties to that contract or the Participating Transmission Owner when there is a dispute.

On a related matter, we disagree with TANC that the ISO Tariff needs to be clarified with respect to the use of the ISO ADR procedure and Existing Contracts. As stated in the ISO Tariff, the ISO will not be involved in interpreting Existing Contracts and therefore disputes between parties to an existing contract should resolve their disputes by utilizing the ADR procedure provided for in that contract. To the extent a dispute involves an entity not party to the ISO Tariff, such as a Non-Participant Transmission Owner or a transmission rights holder under an existing contract, we agree with the ISO/PX that the ISO ADR procedure is available on a voluntary basis to such entity to resolve the dispute. We also agree with the ISO/PX and reject BPA's suggestion that disputes involving the negotiation of new terms under an existing contract be resolved by the Commission on a case-by-case basis. It is inappropriate for either the ISO or the Commission to be involved in negotiating new terms under an existing contract. Moreover, neither the ISO nor this Commission has the time or resources to dedicate to such endeavors.

Right to Revert to Existing Contracts

TANC and others argue that a Participating Transmission Owner, upon withdrawing from the Transmission Control Agreement, should retain the right to restore its existing contractual rights unless and until its existing contract has expired or terminated. 201/ We agree that a Participating Transmission Owner that elects not to convert its existing rights (Non-Converted Rights) during the five-year transition period (i.e., maintains

the existing operating protocols under its Existing Contracts) should be able to withdraw from the Transmission Control Agreement and resume service under its previously existing contract, so long as that contract had not expired or been terminated. However, we do not agree that a Participating Transmission Owner who has converted its Existing Rights to conform to the ISO's operating practices and procedures should be permitted to withdraw from the Transmission Control Agreement and resume service under its previous contract. Section 2.4.4.3 of the ISO Tariff provides that a party electing to convert its rights under an Existing Contract must amend that contract to state that all future transmission service will be provided in accordance with the ISO's scheduling,

200/ TANC September 2, 1997, Comments at 78.

201/ TANC September 2, 1997, Comments at 63-67.

Congestion Management and curtailment protocols. 202/ As we stated above, to the extent that an entity makes a commitment to join the ISO and operate under the ISO's operating practices and procedures, that entity should be prepared to terminate its rights under its existing arrangements. We anticipate that all parties will carefully weigh the benefits and costs of ISO participation, and the commitment to joining the ISO and operating under its rules and protocols.

Duplicative Charges

ISO Tariff Section 2.4.4.1.2 states in part that:

> In addition, the Participating TO shall attempt to negotiate changes to provisions in the Existing Contract to ensure that whenever transmission services under the Existing Contract are used to deliver power to a Market Participant that is subject to Access Charges under this Tariff, no duplicative charge for access to the ISO Controlled Grid will be charged under the Existing Contract. For purposes of such negotiations, there shall be a presumption that any charges in an Existing Contract that were designed to recover the embedded cost of transmission facilities within the ISO Controlled Grid will be fully recovered through the Access Charges established under Section 7.1 of this Tariff.

A number of parties argue that the ISO's proposed amendment to ISO Tariff Section 2.4.4.1.2 should be rejected because it does not adequately clarify that existing contract rights holders will not be liable for access charges. PG&E is concerned that some existing rights holders may use the change to avoid paying the ISO rate, to the detriment of the Transmission Owner's own ratepayers or shareholders, and therefore recommends deleting the new language.

We reject the parties' recommendations to delete the revised language in Section 2.4.4.1.2 of the ISO Tariff. First, we agree with Destec that Section 2.4.4.4.4.3 of the ISO Tariff clearly provides that parties to Existing Contracts will continue to pay the rates provided for under the associated Existing Contracts. Secondly, we interpret Section 2.4.4.1.2 of the ISO Tariff to provide a framework for any voluntary negotiations. In order to

convert service under Existing Contracts to ISO Tariff service, the parties agree that as a basis for negotiations no duplicative charges will be recoverable. That is, customers to an Existing Contract will not pay both the Access Charge and any charge under the Existing Contract. Moreover, we interpret Section 2.4.4.1.2 of the ISO Tariff to in no way obligate a party to an Existing Contract to agree to a change in rate under that Existing Contract.

202/ We also note that Section 3 of the Transmission Control Agreement requires two-years' notice to withdraw from the Transmission Control Agreement.

IV. ISO Tariff

A. Congestion Management

August 15th Filing

The ISO is responsible for managing transmission congestion on the ISO Controlled Grid. The ISO will use a Zone-based approach. A Zone is an area within the ISO Controlled Grid within which there is expected to be little Congestion or relatively low Congestion Management costs. The interfaces between Zones are expected to have relatively high Congestion Management costs. 203/ The ISO/PX initially defined four Zones on the ISO Grid. A Zone is denoted as either Active or Inactive.

Congestion that occurs on the interfaces between Active Zones, defined as Inter-Zonal Congestion, will be managed through the allocation of a Usage Charge to users of the congested interfaces. The Usage Charge will be based on Adjustment Bids. The intention is to allocate Congested Inter-Zonal Interfaces to those who value them the most. The net revenues collected under the Usage Charge will be credited to the owner of each Inter-Zonal Interface. 204/

Congestion that occurs on the interfaces between an Active Zone and an Inactive Zone is also defined as Inter-Zonal Congestion. The costs of managing Congestion on an Inactive Inter-Zonal Interface will be assigned to the Participating Transmission Owner that owns the Inactive interface. The ISO Tariff does not specify the criteria for choosing which generators to redispatch to eliminate Congestion on an Inactive Inter-Zonal Interface, nor does the ISO Tariff specify what compensation these generators will receive.

Congestion that occurs within a Zone is called Intra-Zonal Congestion. The ISO proposes to use "existing operating practices and standard industry scheduling procedures," to manage Intra-Zonal Congestion when the ISO commences operations. 205/ The practices and procedures are not specified in any detail. However, the Tariff does contain a more fully delineated methodology for managing Intra-Zonal Congestion that will be implemented at a future, unspecified date.

203/ ISO Tariff, August 15, 1997, Section 7.2.1.2.

204/ There will be just one relevant Inter-Zonal interface for Congestion Management purposes in the initial structure of the market. It is t interface between the Northern and Southern Zones and is owned by PG

205/ ISO Tariff, August 15, 1997, Section 7.2.6.1.7.

1. Inter-Zonal and Intra-Zonal Congestion Management as Described in the August 15 Filing

The ISO will manage Inter-Zonal Congestion in the Day-Ahead and Hour-Ahead Scheduling processes as well as in real time by using Usage Charges based on Adjustment Bids. 206/ An Adjustment Bid indicates the prices and associated quantities for which the Scheduling Coordinator is willing to increase the output of the resource [beyond its preferred MW operating point] and sell Energy from that resource to the ISO. . . 207/ It also indicates the prices and associated quantities for which the Scheduling Coordinator is willing to decrease the output of the resource [below its preferred MW operating point] and purchase Energy from the ISO at the resource s location. 208/ Adjustment Bids and Ancillary Services bids cannot be submitted in the Day-Ahead or Hour-Ahead markets for the same capacity. 209/ Market participants who wish to participate in the Congestion Management markets can do so on a voluntary basis by submitting Adjustment Bids to their respective Scheduling Coordinators who will forward those bids to the ISO. No market participant is obligated to participate in these markets.

In the Day-Ahead Scheduling process, the ISO will first determine whether all the Preferred Schedules of Scheduling Coordinators, including the required amounts of Ancillary Services, can be accommodated. If all schedules can be simultaneously accommodated, then the Preferred Schedules become the Final Day-Ahead Schedules. If all schedules cannot be simultaneously accommodated due to transmission constraints, the ISO will use its Congestion Management algorithm and protocols to determine a feasible redispatch using Adjustment Bids. The ISO will then communicate to each Scheduling Coordinator a Suggested Adjusted Schedule and an Advisory Inter-Zonal transmission price, i.e., a transmission Usage Charge. At this point, Scheduling Coordinators are allowed to change both their Day-Ahead Schedules and their Adjustment Bids in response to the advisory information

206/ After the close of the Hour-Ahead Market, all standing Adjustment Bids that contain the required information will be converted to Supplemen Energy Bids. Supplemental Energy Bids and Ancillary Services Bids w be used to acquire and sell Imbalance Energy in real time.

207/ ISO Tariff, Appendix A, Master Definitions Supplement.

208/ Id.

209/ August 15 Filing, Appendix III, Responses to Staff Requests for Additional Information, at 13.

provided by the ISO. 210/ Scheduling Coordinators submit Revised Preferred Schedules and Revised Adjustment Bids to the ISO. If all the Revised Preferred Schedules, including the required Ancillary Services, can be simultaneously accommodated then the Revised Preferred Schedules become the Final Day-Ahead Schedules. If all Revised Preferred Schedules cannot be simultaneously accommodated due to transmission constraints, the ISO will use its Congestion Management algorithm and protocols to determine a feasible redispatch using the Revised Adjustment Bids. This will result in an alternative set of Schedules and Inter-Zonal transmission Usage Charges. The ISO will choose one of the two feasible schedules, either the dispatch based on the initial Preferred Schedules, Adjustment Bids and Ancillary Services Bids or the dispatch based on Revised Preferred Schedules, Revised Adjustment Bids, and Revised Preferred Ancillary Services Schedules to implement as the Final Day-Ahead Schedule. 211/ The ISO will choose the schedule that results in the lower Usage Charge revenues for each hour. Scheduling Coordinators are financially committed to pay the Day-Ahead Usage Charges for the quantities in the Final Day-Ahead Schedule.

In the Hour-Ahead Scheduling process, Scheduling Coordinators can submit new Hour-Ahead Preferred Schedules. Every Scheduling Coordinator can submit new Hour-Ahead Adjustment Bids. If all the Preferred Schedules can be simultaneously accommodated then the Preferred Schedules become the Final Hour-Ahead Schedules. If all Preferred Schedules cannot be simultaneously accommodated due to transmission constraints, the ISO will calculate a feasible redispatch using the Hour-Ahead Adjustment Bids. This redispatch will become the Final Hour-Ahead Schedule and will be used to determine the Hour-Ahead transmission Usage Charges. To the extent that the MW quantity specified in an Hour-Ahead Schedule for a participant differs from the MW quantity specified in the Day-Ahead Schedule, the participant would pay or receive (as applicable) the Hour-Ahead Usage Charge for the difference in quantities.

In real time, the ISO will select Generating Units, Loads and System Resources to meet Imbalance energy requirements. In the event of Inter-Zonal Congestion in real time, the ISO shall

210/ There are restrictions on how an Adjustment Bid can be modified. The range of the Adjustment Bid can be changed, but not the specified pr values.

211/ There is no provision in the ISO Tariff that allows Ancillary Servic Bids to be modified in the Day-Ahead Scheduling process. However, t the extent that participants self-schedule Ancillary Services, these

schedules can be modified concurrently with the Preferred Schedules.

procure Imbalance Energy separately for each Zone. 212/ The ISO will increase or decrease output using Supplemental Energy Bids and Ancillary Services bids. Supplemental Energy Bids come from two sources: (1) Participants can submit them to the ISO up to 30 minutes prior to the operating hour; and (2) An Adjustment Bid becomes a Supplemental Energy bid if it is left standing after the Hour-Ahead Market has closed and it contains the information required for Supplemental Energy bids, e.g., ramp rates. 213/

The ISO Tariff states that, beginning on the ISO Operations Date, Intra-Zonal Congestion Management will be performed in the Day-Ahead and Hour-Ahead Markets "based on existing operating practices and standard industry scheduling procedures." 214/

At "such date as the ISO Governing Board may determine," 215/ the ISO will begin managing Intra-Zonal Congestion using Adjustment Bids. This proposed process for managing Intra-Zonal Congestion will start, for each hour in the Day-Ahead and Hour-Ahead scheduling process, after the Inter-Zonal Congestion is eliminated. Intra-Zonal Congestion management will be done in such a way as to not create or increase Inter-Zonal Congestion, and it will be done in such a way as to minimize the adjustment of Scheduling Coordinators' Preferred or Revised Schedules.

Under this future method, Scheduling Coordinators whose scheduled energy is increased will be compensated by the ISO for the incremental energy at the price specified in the Adjustment Bid for that resource. Scheduling Coordinators whose scheduled energy is decreased will pay the ISO for the reduction in output (or purchase) at the price specified in the Adjustment Bid for the resource. The redispatch costs associated with Intra-Zonal Congestion will be allocated to Scheduling Coordinators regardless of whether the Scheduling Coordinator actually causes the Intra-Zonal Congestion. The allocation of costs will be done through a Grid Operations Charge. The Grid Operations Charge will be paid to the ISO on a monthly basis by all Scheduling Coordinators in proportion to their metered Demand within, and metered exports from the Zone.

212/ ISO Tariff, August 15, 1997, Section 2.5.22.7.

213/ August 15 Filing, Appendix III, Responses to Staff Requests for Additional Information, Question 35(a), p. 22. We note that there i language in the ISO Tariff that explains the process by which Adjust Bids become Supplemental Energy Bids.

214/ ISO Tariff, August 15, 1997, Section 7.2.6.1.7.

215/ ISO Tariff, August 15, 1997, Section 7.2.6.1.7.

Contested Issues Identified by the ISO/PX

TURN/UCAN contend that the proposed PX Activity Rules should also be applied to the Congestion Management market. 216/

September 2, 1997 Comments

San Francisco requests rehearing of the Commission s approval of ISO/PX congestion pricing proposal stating that the Commission erred in finding that it did not violate and pricing. 217/ M-S-R Public Power Agency, Santa Clara, Redding and Palo Alto, Metropolitan, TANC and Modesto also argue that the Commission erred in approving the concept of congestion pricing proposed by the ISO/PX. These parties assert that the ISO s congestion management proposal is unjust and unreasonable since it: (1) results in improper cost shifts among customer groups, (2) constitutes improper and pricing, and (3) does not pass muster under the Commission s Transmission Pricing Policy Statement. 218/

BART requests that it be exempted from payment of congestion Usage Charges in connection with the delivery of BART s purchases of federal preference power. 219/ According to BART, application to BART of congestion Usage Charges would be inconsistent with the purpose of pre-existing state legislation conferring rights upon BART to transmission service by PG&E. 220/ BART claims that the assumption underlying this legislation was that PG&E transmission service to BART would be priced at average embedded cost, and that the purpose of Section 701.8 was to prevent any unusual pricing or other delivery conditions that might impede the public purpose of encouraging the use of BART. BART states that it entered into long-term take-or-pay contracts to purchase preference power from BPA in reliance on average embedded cost

216/ TURN/UCAN at 113-114.

217/ August 29, 1997 Request for Rehearing of San Francisco at 3.

218/ Metropolitan at 22-23; TANC at 25; Modesto at 24; and M-S-R and Sant Clara, Redding and Palo Alto at 24-25.

219/ BART states that it is a preference entity as defined by section 9(c the Reclamation Project Act of 1939, 43 U.S.C. Section 485h(c), and purchased federal preference power since 1994.

220/ See Section 701.8 of the California Public Utilities Code (chapter 6 statues of 1995).

transmission pricing. 221/ Accordingly, BART recommends amendment of the ISO and PX Master Definitions Supplements definition of Eligible Customer to state:

> No provision of this tariff shall be applied in a manner that is contrary to the policy or requirements of Section 701.8 of the California Public Utilities Code. Usage Charges for Inter-Zonal Congestion shall not apply to deliveries of preference power to BART pursuant to Section 701.8.

CCEM contends that the ISO intends to unilaterally implement a congestion pricing scheme that is different from the model contained in the ISO Tariff. According to CCEM, the pricing model contained in the Tariff was agreed to by the Market Participants and is central to the transparent bidding process. Specifically, CCEM notes that although ISO Tariff Section 7.2.5.2.2. requires the ISO to calculate the Usage Charge based on the value of the congested path, rather than on zonal prices, the ISO s response to Staff s questions indicate that pricing will be based on a zonal pricing scheme which is determined by using a complex optimal power flow model. Furthermore, CCEM notes that the ISO will also use its optimization program in other contexts in contravention of the language of the tariff. CCEM recommends that the Commission direct the ISO to reinstate its original zonal pricing methodology, whereby all resources within a zone would be deemed to be at the same virtual location. 222/

CCEM opposes the restriction against submitting an ancillary services bid and an adjustment bid for the same capacity. 223/ According to CCEM, the sequential bidding processes for each of the products auctioned by the ISO precludes any risk of the same resource capacity being committed twice. 224/

The CEC notes that there are a number of remaining unresolved congestion management details which are critical. CEC

221/ BART at 1-5.

222/ CCEM at 17-21.

223/ See August 15 Filing, Appendix III, Responses to Staff Requests for Additional Information, at 13.

224/ CCEM at 16.

reserves the right to comment on these additional details as they are filed. 225/

Commission Response

The Commission preliminarily accepted the Companies congestion pricing and Usage Charge proposal in the November 26, 1996, Order. 226/ Specifically, the Commission stated, ...the Companies proposal to establish some form of congestion-based transmission usage charges is a positive step towards alleviating transmission congestion efficiently... However, the Order required the ISO/PX to demonstrate that: (1) market power in the energy market could be adequately mitigated; and (2) the proposal would not result in and pricing.

In the July 30 Order, the Commission accepted the conceptual framework of the ISO s congestion pricing proposal. 227/ The Commission stated that, ...The usage charge will encourage efficient usage of the transmission system and facilitate the development of a competitive electricity market. The Commission found that ...the circumstances here are distinguishable from the historical circumstances in which we outlined our and pricing policy. ...we believe that the ISO s transmission pricing proposal is fully consistent with our Transmission Pricing Policy Statement. Therefore, the Commission concluded that the ISO s transmission pricing proposal does not raise the same concerns with regard to and pricing addressed in the November order.

The Commission denies the requests of M-S-R and others, for rehearing and protests on the congestion pricing proposal. We note that these pleadings simply repeat arguments that have been fully addressed in our prior order. The congestion pricing proposal does not result in improper cost shifts among customer groups. As we stated in our July 30 Order, the congestion pricing proposal efficiently rations constrained transmission capacity by assigning a transmission Usage Charge to those who use the congested Inter-Zonal interface. 228/ This sends the proper price signals regarding the opportunity costs of using congested transmission paths. We also stated in our July 30 Order that the proposed congestion pricing proposal does not result in and pricing. The proposal provides for the recovery

225/ CEC at 14.

226/ November 26 Order, 77 FERC at 61,831.

227/ July 30 Order, 80 FERC at 61,429.

228/ Id.

of each Transmission Owner s revenue requirement. It does not allow for an over-recovery of the revenue requirement. In addition, the proposal does not discriminate among classes of customers. All customers pay an Access Charge to use the ISO Grid, and all customers who, in addition, use a congested interface pay a transmission Usage Charge. Therefore, as

articulated in our July 30 Order, we believe that the ISO s transmission pricing proposal is fully consistent with our Transmission Pricing Policy Statement. The proposal 1) meets the revenue requirement, 2) reflects comparability, 3) promotes economic efficiency, 4) promotes fairness, and 5) is practical. 229/

The ISO Tariff states that existing operating practices and standard industry scheduling procedures will be used for managing Intra-Zonal Congestion on the ISO Operations Date. The Commission is unaware of any existing operating practices and standard industry scheduling procedures for resolving congestion in California that are on file with the Commission. Thus, the ISO has not adequately specified the practices and procedures that it will use to manage Intra-Zonal Congestion when the market begins operations. The Commission directs the ISO to file the specific practices and procedures, including a description of how any costs will be calculated and recovered, that the ISO will use on the ISO Operations Date to resolve Intra-Zonal Congestion. We direct the ISO to modify its Tariff to incorporate these changes.

We require that the ISO Tariff contain only those provisions that will be implemented on the ISO Operations Date. The ISO must delete those sections that will not be in effect on that date. With regard to managing Intra-Zonal Congestion using Adjustment Bids, we require that the ISO delete Sections 2.5.22.8, 7.2.1.4.2, 7.2.4.1.3, 7.2.6.1, 7.2.6.1.1 through 7.2.6.1.6, 7.3.2, and 7.3.2.1. The ISO may refile these sections when it is prepared to implement them. However, when the ISO refiles these sections they should be clarified. In particular, Section 7.2.6.1.2 states that the ISO in fulfilling its objective to minimize the changes to Scheduling Coordinator's Preferred or Revised Schedules will "weight" the changes to the Schedules. Based on this "weighting," the ISO will create a merit order stack of resources that will be used to manage Intra-Zonal Congestion. This weighting scheme needs to be more fully explained and justified. In addition, the ISO is directed to file all Intra-Zonal Congestion Management protocols, at the time the tariff provisions are refiled, as these protocols are necessary to more fully understand the process by which the ISO proposes to manage Intra-Zonal Congestion.

229/ July 30 Order, 80 FERC at 61,430.

TURN/UCAN contend that the proposed PX Activity Rules should also be applied to the Congestion Management market. The Commission notes that since the PX Activity Rules have not yet been filed, we cannot evaluate at this time whether these rules will be appropriate for the Congestion Management market. Therefore, TURN/UCAN's proposal is premature. After the Activity Rules are filed, TURN/UCAN may file this proposal again. 230/

The Commission denies BART s request to amend the ISO and PX definition of Eligible Customer in the Master Definitions Supplement.

To the extent that BART has a pre-existing contractual relationship with PG&E, this should be listed as an encumbrance in Appendix B of the Transmission Control Agreement.

CCEM claims that the two examples set out in Attachment 6 of the ISO's response to Question 9 of the Commission Staff's Request for Additional Information propose a different pricing scheme for Inter-Zonal Congestion than that contained in the ISO Tariff. We cannot determine whether CCEM s assertion is correct. First, the examples are too simple for us to determine whether they are based on a Zonal pricing scheme, which is determined by using a complex optimal power flow model. Second, as pointed out by several intervenors, Example 2 contains errors. Specifically, the values of transmission for each Scheduling Coordinator are not reflected in the revised schedule. Thus the conclusions are based on erroneous marginal costs. 231/ The Commission will need to review the Congestion Management protocols that the ISO when they are filed. At that time, the Commission will make a determination about which parts of the protocols may need to be incorporated in the ISO Tariff and whether the details in the protocols are consistent with the conceptual pricing scheme described in the ISO Tariff.

In response to CCEM's comment, we will require the ISO to permit a participant to submit Ancillary Service Bids and an Adjustment Bid for the same capacity in the Day-Ahead and Hour-Ahead markets. As noted by CCEM, the ISO Tariff does not allow a resource to submit an Ancillary Services bid and an Adjustment Bid for the same capacity. In the July 18, 1997 Response to Commission Staff's Requests for Additional Information, Question 13, the ISO explained that Ancillary Services Bids and Adjustment Bids could not be submitted for the same capacity because "a Scheduling Coordinator will not know when it submits Adjustment Bids whether its units/resources may also be selected to provide Ancillary Services. Therefore, if it offered the same capacity

230/ See the PX Tariff section of this order, Commission Response to Contested Issues Identified by the ISO/PX.

231/ See the PX Tariff section of this order, PX Overcollection of Revenu

in both markets it would risk being unable to fulfill its obligation when called upon."

As CCEM has noted, the Ancillary Services auction and the Congestion Management process are sequential, thus there is no risk that the same capacity will be committed twice. Moreover, the Ancillary Services Markets are also in fact four sequential markets, and the ISO does not prohibit bids from the same capacity to be submitted for all four markets. To the contrary, bids for the same capacity are considered sequentially in each Ancillary Services market until accepted. The Commission sees no reason why the same procedure cannot be used with regard to the Congestion Management market. The ISO should revise its Tariff to reflect this change in its compliance filing. To the extent

that the ISO is unable to implement this change on the ISO Operations Date, the ISO should indicate why implementation must be delayed and at what date it expects to implement the change.

In the Day-Ahead Scheduling process, the ISO will announce to each Scheduling Coordinator a Suggested Adjusted Schedule and an Advisory Inter-Zonal transmission price (the Usage Charge) when the initial set of Preferred Schedules cannot be accommodated due to transmission constraints. The Commission will require the ISO to announce additional information, consistent with the Day-Ahead Information identified in Section 6.1.2.2.2 of the ISO Tariff, to be posted on WEnet, about the Advisory Redispatch. In addition to the above information, the ISO is directed to announce to each Scheduling Coordinator the amount of Inter-Zonal Congestion between Active and Inactive Zones, the amount of Intra-Zonal Congestion, and for each resource that is rescheduled, the reason it was rescheduled: to eliminate Inter-Zonal Congestion between Active Zones, to eliminate Inter-Zonal Congestion between Active and Inactive Zones, or to eliminate Intra-Zonal Congestion.

This information is needed by Scheduling Coordinators in order to understand their financial liability under the schedule and to formulate Revised Preferred Schedules and Revised Adjustment Bids. Payments between a resource and the ISO will be affected differently depending upon the reason the resource s Preferred Schedule was changed. There may be positive payments between a resource and the ISO if the resource is rescheduled to resolve Intra-Zonal Congestion. There are no payments between a resource and the ISO if the resource is rescheduled to resolve Inter-Zonal Congestion. In the case of Inter-Zonal Congestion, the resource is rescheduled to avoid paying a Usage Charge for Inter-Zonal transmission. Market Participants need to fully understand the nature of Congestion on the ISO Grid to accurately formulate Revised Preferred Schedules and Revised Adjustment Bids in the Day-Ahead Scheduling process.

The criteria proposed by the ISO in the Day-Ahead Scheduling process to choose between the two alternative schedules may not result in the scheduling of the lower cost set of generators. 232/ The proposed criteria is "minimizing the Usage Charge revenues to the ISO for Inter-Zonal Congestion." However, minimizing the Usage Charge revenues may not result in a more efficient and competitive electricity market. This goal requires allocating transmission to those who value it most. A reasonable presumption is that a Revised Adjustment Bid and a Revised Preferred Schedule better reflect a market participant s value or cost than an earlier bid or schedule, so that a Final Schedule based on revised information will be more likely to allocate transmission to those who value it most. While the Revised Bid Schedule may reduce prices overall, the Commission will accept the ISO proposed criterion to minimize Usage Charges. This decision is consistent with ISO Principle No. 6 which says that the ISO will take actions to relieve constraints within the trading rules established by the governing body. This principle also says that these rules should promote efficiency, and thus there may be a tension between these rules and minimization of

energy prices. While the ISO proposal is acceptable in these circumstances, we will closely monitor its scheduling practices.

Adjustment Bids may be submitted by loads. The definition of an Adjustment Bid found in Appendix A of the ISO Tariff is incomplete with respect to loads. The Commission directs the ISO to incorporate sections equivalent to (v) and (vi) that address the form of an Adjustment Bid that a load would submit.

We will direct the ISO to make publicly available the algorithm that it uses to manage Inter-Zonal Congestion. Market participants need to understand how dispatch decisions are made by the ISO. We believe that the actions of the ISO should be transparent, i.e., the ISO should not be operating within a "black box." Also, public availability of the ISO's Inter-Zonal dispatch algorithm will allow market participants to test the algorithm with historic or alternative data and find ways to correct problems or otherwise improve upon the algorithm.

We also direct the ISO to modify the ISO Tariff to explicitly state the process by which Adjustment Bids left standing after the close of the Hour-Ahead market become Supplemental Energy bids in the balancing market.

2. Balanced Schedules and the Usage Charge

232/ The two schedules consist of the dispatch based on the initial Preferr Schedules, Adjustment Bids and Ancillary Services Bids and the dispa based on Revised Preferred Schedules, Revised Adjustment Bids, and Revised Preferred Ancillary Services Schedules.

August 15th Filing

The ISO will use Adjustment Bids submitted by Scheduling Coordinators to resolve Inter-Zonal Congestion and determine the Usage Charge (transmission price) for the use of a congested interface between Active Zones. 233/ In the process of resolving the Inter-Zonal Congestion, the ISO will keep each Scheduling Coordinator's portfolio of generation and load balanced after adjusting for allocated losses.

A Scheduling Coordinator that wishes to participate in the Congestion Management market must have generation or load in both of the Active Zones. The ISO's computer optimization algorithm will calculate a Scheduling Coordinator's implicit value of Inter-Zonal Transmission based on the difference between the price for increasing generation (or decreasing load) in one Zone and the price for reducing generation (or increasing load) in the other Zone. 234/ The ISO's computer optimization algorithm will then stack the implicit values for transmission from lowest to highest. Scheduling Coordinators with a high value for transmission will be scheduled to transmit over the path in lieu of other Scheduling Coordinators with a lower value for the transmission. Thus, congestion will be resolved by redispatching the units of the Scheduling Coordinators with the lowest

valuation of transmission and sequentially working up the stack to the point where congestion is eliminated. The Usage Charge for congested transmission will be set equal to the lowest implicit value of transmission of the Scheduling Coordinators that are scheduled to transmit over the interface. This is the marginal value of the congested interface. Every transaction scheduled over a given Congested Inter-Zonal Interface in an hour will pay the same per kW Usage Charge.

The ISO Tariff offers to provide a mechanism to facilitate voluntary trades among Scheduling Coordinators for those Scheduling Coordinators who request such a mechanism and authorize the publication of their identities and/or Adjustment Bids. 235/

233/ The Congestion Management process described in this section does not apply to Inter-Zonal Congestion between an Active and Inactive Zone.

234/ This discussion is based on the example contained in Attachment 6 of Responses to Requests for Additional Information made by the Commiss Staff on July 18, 1997. There are no details on the methods used to resolve Inter-Zonal Congestion in the ISO Tariff filed on August 15, 1997.

235/ ISO Tariff, August 15, 1997, Sections 7.2.2.6 and 7.2.4.1.5.

Contested Issues Identified by the ISO/PX

One of the market design principles of the ISO proposal is that each Scheduling Coordinator must submit balanced schedules that are not centrally determined by the ISO. One consequence of this design principle is that, in dealing with congestion, each Scheduling Coordinator will be able to submit to the ISO Adjustment Bids while maintaining a balanced schedule within its portfolio. The scheme does not contemplate the ISO attempting to reoptimize between Scheduling Coordinators by selecting the best Adjustment Bids across Scheduling Coordinators and, in effect, imposing trades between them.

TURN/UCAN characterizes this market design principle as a "market separation constraint." TURN/UCAN and others criticize it as likely to impede the ISO's efforts to use transmission resources efficiently. 236/ CEC contends that the current language of the ISO Tariff, contained in Sections 7.2.2.3 and 7.2.2.6, inefficiently precludes the ISO from using Adjustment Bids to create a single market clearing price that uses all loads and resources in economic merit order. CEC has suggested that the ISO should play an active role in arranging voluntary trades between Scheduling Coordinators to assist in dealing with Congestion. 237/

CEC contends that the ISO Tariff falls short of the Commission's requirement that "the ISO be allowed to use all information it receives in order to develop a least cost schedule

in performance of its responsibilities to efficiently manage congestion." 238/ CEC suggests that Sections 7.2.2.3 and 7.2.2.6 preclude the ISO from using Adjustment Bids to create a single market clearing price that use all loads and resources in economic merit order. CEC points out that under the ISO Tariff the ISO must only increase and decrease loads and resources within each Scheduling Coordinator portfolio to maintain balanced schedules which then leads to multiple market clearing prices, the scheduling of higher cost resources ahead of lower cost resources, and a potentially inefficient result. 239/

CEC also argues that this problem was resolved in the Steering Committee process and language was drafted (and later circulated) to reflect the consensus reached by the stakeholders

236/ See, e.g., TURN/UCAN at 117-121.

237/ CEC at 9-10.

238/ See November 26 Order, 77 FERC at 61,810.

239/ CEC at 5-6.

in a preliminary draft of the Phase II Filing. 240/ CEC now contends that the current language does not reflect the original intent of the compromise reached by the Steering Committee. Specifically, the current language limits publication of Adjustment Bids to those where the Scheduling Coordinator has authorized release of the bidder's identity and thus eliminates the ISO's role as a neutral broker.

The CEC requests that, based on the consensus reached by the Steering Committee, the Commission condition its approval of the ISO Tariff on the establishment of a coded bid bulletin board and the provisional implementation of a bid-based market allowing the Scheduling Coordinators to find and make efficient trades with one another without identifying those who submit Adjustment Bids. 241/

June 23, 1997 ISO/PX Reply Comments

The ISO Governing Board, at its meeting on June 12, 1997, decided to oppose the CEC s proposal. It felt that there was no reason that market forces cannot be relied on in this, as in other cases, to achieve the efficient outcome that the CEC would like to see.

According to the ISO/PX, the assertion that centralized reoptimization by the ISO will permit it to use transmission resources more efficiently is true only to the extent that a market or markets do not develop to allow Scheduling Coordinators to trade incremental and decremental bids to achieve an efficient outcome. Such a market could be implemented in the form of a bulletin board or through the publication of coded bids with the

consent of the relevant Scheduling Coordinators. The ISO Tariff allows the ISO to facilitate the development of such a market. 242/ Given the economic incentives on Scheduling Coordinators to trade, the ISO/PX consider it most appropriate to allow these markets to develop without having the ISO play an active role in arranging the trading of Adjustment Bids. 243/

September 2, 1997 Comments

240/ CEC at 8.

241/ CEC at 10.

242/ ISO Tariff Section 7.2.4.1.5.

243/ ISO/PX June 23, 1997 Reply Comments at 363.

Nymex supports the Phase II proposal to base congestion pricing on adjustment bids (as opposed to the Phase I proposal to base such pricing on the market clearing energy prices determined by the PX). Nymex states the filing may imply an intention in the future to return to the Phase I approach. Nymex assumes that any change in approach would require Commission approval. 244/

CEC claims that the August 15 Filing underscores its recommendations that the ISO Tariff should be modified to provide a mechanism for Scheduling Coordinators to be informed of cost reducing opportunities that are disclosed in the Adjustment Bids provided to the ISO for congestion management purposes. 245/

Commission Response

The CEC has pointed out that in the first example in Attachment 6 of the ISO/PX Responses to Staff's Request for Additional Information on July 18, 1997, the restriction that Scheduling Coordinators schedules remain balanced in the Congestion Management process results in significant inefficiencies. Although the ISO/PX maintain that the ISO should keep each Scheduling Coordinator s schedule balanced so that no trades between Scheduling Coordinators are arranged in the Inter-Zonal Congestion Management process, the Commission notes that there are at least three situations in which the ISO does allow schedules to be unbalanced. Scheduling Coordinators do not have to maintain balanced schedules in the proposed Intra-Zonal Congestion Management process, in Overgeneration situations (when scheduled Eligible Regulatory Must-Take, Eligible Regulatory Must-Run, and Reliability Must-run resources exceed the aggregate PX load), and when Reliability Must-Run generation is scheduled.

We will accept the ISO's requirement that the ISO resolve Congestion by keeping each Scheduling Coordinator's schedule balanced in the Day-Ahead and Hour-Ahead Scheduling processes.

However, to reduce the inefficiencies of the sort described by the ISO/PX in their example in Attachment 6 that may otherwise result, we will suggest and provide for various measures to alleviate potential inefficiencies.

We encourage the ISO to consider the CEC s proposal. However, we will not require it at this time. The ISO has said that it will put in place a mechanism to facilitate trades if requested, and when it can develop the needed software. The Commission believes it is important for the ISO to develop these kinds of mechanisms as needs arise. ISO Principle No. 6

244/ Nymex at 5.

245/ CEC at 2-6.

emphasizes that trading rules should be established by the governing body.

We see merit in the CEC s assertion that the availability of coded information could increase trading opportunities and improve the Day-Ahead Schedule by facilitating a process whereby cheaper generation is scheduled to run. The CEC s proposal should allow the ISO to facilitate voluntary trades among Scheduling Coordinators without forcing Scheduling Coordinators to trade. The ISO contends that a market or markets will develop to allow Scheduling Coordinators to trade Adjustment Bids if an efficient outcome is not reached in the ISO scheduling process. That is an unresolved question. We believe that the ISO may be in a unique position to facilitate trades, because it may be the only entity that will have all the relevant information gathered together. It might be inefficient for market participants to incur search costs to find beneficial trades when the ISO already has the information that they need.

In order to facilitate the Congestion Management process and to inform market participants about potential trading opportunities, we will direct the ISO to publish certain non-confidential information, by March 31, 1998, or when technically feasible. Specifically, we direct the ISO to compute, for each Advisory and Final Schedule in the Day-Ahead and Hour-Ahead markets, the dispatch and Usage Charges that would have resulted if the ISO had been allowed to resolve Congestion without the restriction that Scheduling Coordinators keep their schedules balanced. This dispatch is exactly the dispatch that the ISO would have found had all Adjustment Bids been submitted by a single Scheduling Coordinator instead of by various Scheduling Coordinators. Consequently the implementation of this extra computation would require only a relabeling of the input data (by attributing all Adjustment Bids to a single Scheduling Coordinator) and would not require any modification of the computational part of the Congestion Management software. The Commission will require only that the Usage Charges and not the actual dispatch be published simultaneously with the Advisory and Final Usage Charges. The Usage Charges should be published for every hour in the Day-Ahead and Hour-Ahead market.

The publication of this unrestricted Usage Charge will inform market participants about potential trading opportunities. If in fact, there is a large potential for additional trades, and market participants are unable to uncover these trades, there will be a strong incentive for market participants to develop trading mechanisms or to request that the ISO put one in place pursuant to Sections 7.2.2.7 and 7.2.4.1.5 of the ISO Tariff.

4. Congestion Zones

August 15th Filing

Four Zones are defined on the ISO Controlled Grid. There are two Active Zones, the Northern Zone and the Southern Zone, and two Inactive Zones, the Humbolt Zone and the San Francisco Zone. 246/ An Active Zone is defined as a Zone for which there are "workable competitive generation markets" on both sides of the defined Inter-Zonal Interfaces for a substantial portion of the year. 247/ An Inactive Zone, consequently, is defined as a Zone that does not have workable competition on at least one side of the Inter-Zonal Interfaces. The ISO Tariff does not define "workable competitive generation markets." The ISO Governing Board is responsible for developing such criteria.

The ISO will establish a transmission price (or Usage Charge), using Adjustment Bids, between Active Zones. The ISO will not establish a price for transmission, using Adjustment Bids, for transmission between an Inactive Zone and an Active Zone. The costs of managing congestion (the redispatch costs) on the interfaces between an Inactive Zone and an Active Zone will be allocated to the Service Area of the Participating Transmission Owners who own the Inactive Inter-Zonal Interface. 248/ For the purposes of Intra-Zonal congestion management, an Inactive Zone will be considered part of an adjacent Active Zone, and the costs of Intra-Zonal congestion will be allocated across the two Zones as if they were one.

The ISO expects to create, eliminate and modify the Zones from time to time as changes in patterns and levels of transmission congestion dictate. The ISO will monitor the grid and determine if changes are necessary. The creation of a new Zone will be considered if over the course of a 12-month period "the cost to alleviate the Congestion on a path is equivalent to at least 5% of the product of the rated capacity of the path and the weighted average Access Charge of the Participating Transmission Owners." 249/

Contested Issues Identified by the ISO/PX

246/ The Northern Zone largely coincides with PG&E's current service territory. Both of the Inactive Zones are located entirely within t Northern Zone. The Southern Zone encompasses the southern portion o PG&E s system as well as all of Edison s and SDG&E s transmission

systems.

247/ ISO Tariff, August 15, 1997, Section 7.2.7.3.1.

248/ ISO Tariff, August 15, 1997, Section 7.2.7.3.3.

249/ ISO Tariff, August 15, 1997, Section 7.2.7.2.1.

SMUD contends that the Intra-Zonal Congestion Management costs within an Inactive Zone should be allocated to the Service Area of the Participating Transmission Owner owning the Inactive Zone rather than spread across the adjacent Zone. SMUD argues that such costs should be allocated similarly as Congestion Management costs between an Inactive Zone and an Active Zone, i.e., to the Service Area of the Participating Transmission Owner which owns the Inactive Zone. 250/

Santa Clara and Palo Alto contend that the 5 percent Access Charge differential trigger for the establishment of Congestion Zones has not been shown to be just and reasonable. Santa Clara and Palo Alto: (1) oppose the concept of Congestion Zones; (2) if Congestion Zones are retained, support the concept of Active/Inactive Zones; (3) oppose the 5 percent Access Charge differential trigger for the establishment of Congestion Zones; (4) believe that new Congestion Zones should be established only with the Commission's approval; and (5) believe that the Commission's approval process should include an assessment of whether the 5 percent Access Charge differential trigger is just and reasonable. 251/

Santa Clara and Palo Alto argue that the concept of Congestion Zones is improper because congestion may occur due to physical geographic constraints and the local utility's previous decisions which result in under-construction of transmission, or construction of generation in lieu of transmission. 252/

San Francisco supports the designation of the San Francisco Zone as Inactive and urges the Commission to support the concept of Active and Inactive Zones. San Francisco believes that if it is not designated as an Inactive Zone then electric consumers in San Francisco may become subject to monopolistic rents for Congestion as competition does not exist in that Zone. 253/

June 23, 1997 ISO/PX Reply Comments

With regard to SMUD s complaint, the ISO/PX responds that the rule in Section 7.2.7.3.3 reflects the position as determined through the consensus process leading up to the Phase II filing. In their view, to allocate the Intra-Zonal Congestion costs within an Inactive Zone to the Participating Transmission Owner

250/ SMUD at 32-34.

251/ Santa Clara at 9; Palo Alto at 10.

252/ Santa Clara at 9; Palo Alto at 10.

253/ San Francisco at 6.

which owns that Inactive Zone would fail to recognize that the Congestion could have been caused by any Scheduling Coordinator scheduling in that Inactive Zone. Further, the costs of Intra-Zonal Congestion within the Inactive Zone will, by definition, be limited. 254/

In response to Santa Clara and Palo Alto, the ISO/PX state that in its November 26 Order, the Commission accepted the proposal to establish zones for the purpose of assessing congestion usage charges. 255/ They characterize the Cities argument as a late attack on the Commission's November 26 Order and argue that Santa Clara and Palo Alto should have raised this issue in that proceeding. 256/

The ISO/PX contend that they addressed the issue of the appropriateness of the 5 percent Access Charge differential trigger in their May 20 Response. There, the ISO/PX states that, ...until some experience of operating the new market has been acquired, it is not possible to quantify the likely costs of Congestion across congested paths. The threshold figure of 5 percent was agreed between stakeholders on the basis that the costs of Congestion would need to reach significant levels in order to provide an incentive for transmission expansion. 257/ In addition, the ISO/PX state that there is no dispute that the Commission may choose to assert jurisdiction in relation to these parties' proposal that the Commission should, under section 205 of the FPA, review the appropriateness of the 5 percent trigger when a new Congestion Zone is proposed.

Commission Response

In the November 26 Order, the Commission approved the concept of four zones for managing congestion proposed in the Phase I Filing. In the March 31 and August 15 filings, the ISO/PX designated two of these Zones, the Humbolt Zone and the San Francisco Zone, as Inactive Zones, and the other two zones as Active Zones. The Commission approves the proposed designation of Active and Inactive Zones. 258/

254/ ISO/PX June 23, 1997 Reply Comments at 64.

255/ See November 26 Order, 77 FERC at 61,831-61,832.

256/ ISO/PX June 23, 1997 Reply Comments at 70.

257/ Response of the ISO and PX to Request for Additional Information, Ma 20, 1997, at 29.

258/ San Francisco filed a rehearing request on Dec. 26, 1996, protesting (continued...)

SMUD states that the ISO's proposal satisfies its primary concerns with respect to the allocation of Inter-Zonal congestion management costs on the Inactive Inter-Zonal Interface. With respect to SMUD's concerns pertaining to the allocation of Intra-Zonal congestion management costs associated with Inactive Zones, we note that the ISO states that Intra-Zonal congestion costs are likely to be small. On this basis, we believe that it is appropriate to initially allocate Intra-Zonal Congestion Management costs across an Inactive Zone and the adjacent Active Zone as if the two Zones were a single Zone as proposed by the ISO in Section 7.2.7.3.3. However, the ISO has not yet filed the method by which it will calculate and assign Intra-Zonal Congestion Management costs. We will have the opportunity to further evaluate the ISO's congestion management proposal both when it submits the required ISO Tariff revisions and when it submits the required study to evaluate Zones, as set out below.

We note that Section 7.3.2 of the ISO Tariff provides that Scheduling Coordinators will pay the ISO a Grid Operations Charge 259/ on a monthly basis, "in proportion to their metered demand within, and metered exports from, the Zone." However, the definition of the Grid Operations Charge states that, "These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their customers' Demand on a Zone by Zone basis." We have directed the ISO to delete sections of the ISO Tariff which will not go into effect on the ISO Grid Operations date but which will be staged. This includes Section 7.3.2. However, we note that the definition of the Grid Operations Charge is not consistent with Section 7.3.2. We direct the ISO to modify the definition of Grid Operations Charge so that it is consistent with the ISO tariff revisions pertaining to the calculation and assignment of Intra-Zonal Congestion costs.

The Commission approves the 5 percent criterion for the consideration of new Zones by the ISO, subject to further review, as discussed below. We consider the 5 percent criterion a starting place. There is a trade-off between the administrative convenience of fewer Zones and the inefficiency of Congestion within a Zone. The proposed method for managing Intra-Zonal Congestion will spread the costs over all Scheduling Coordinators within a Zone regardless of whether a Scheduling Coordinator creates Intra-Zonal Congestion or not. Also, the proposed method for managing Inter-Zonal Congestion between Inactive and Active

258/ (...continued)
designation of San Francisco as an Active Zone. This request is now moot since San Francisco has been designated an Inactive Zone.

259/ The Grid Operations Charge recovers redispatch costs associated with Intra-Zonal congestion.

Zones allocates the costs to the owner of the Inactive interface which will be paid by the owner's transmission customers. Again, the charge will be paid by customers regardless of whether they cause Inter-Zonal Congestion between the Active and Inactive Zone. As the ISO gains more experience and information about the way the market operates, it may be appropriate to refine the 5 percent criterion. The ISO may find it appropriate to consider other criteria for zonal review. We direct the ISO to conduct a study that evaluates the effectiveness of the 5 percent criterion for considering whether to create or modify Zones and to file a report no later than January 1, 1999. The study should include the following information and analyses:

1) The total number of MWs and the associated redispatch costs of Intra-Zonal Congestion within each Active and Inactive Zone, for each hour in the Day-Head and Hour-Ahead Schedules, starting from the date the ISO commences operations.

2) The total number of MWs and the associated redispatch costs of Inter-Zonal Congestion between each Inactive and adjacent Zone, for each hour in the Day-Ahead and Hour-Ahead Schedules, starting from the date the ISO commences operations.

3) The effects of activating the Inactive Zones on Usage Charges, and the MWs and redispatch costs calculated in (1) and (2) above.

In addition, since an Inactive Zone is defined as not having "workable competition" on at least one side of the Inter-Zonal interface, the study should also include,

4) The effectiveness of all proposed mechanisms for mitigating market power within an Inactive Zone, including call contracts, divestiture, and transmission rights, and whether these mechanisms cause there to be workable competition in the Inactive Zone.

The Commission will reconsider the appropriateness of the 5 percent criterion after evaluating the results of the study ordered above.

The ISO Tariff does not specify how or when, during the Day-Ahead and Hour-Ahead scheduling process, the costs of Inter-Zonal Congestion between Inactive and Active Zones will be calculated. The Commission directs the ISO to amend the ISO Tariff to specify (1) the timing for resolving Inter-Zonal Congestion between Active and Inactive Zones, that is, whether the process will take place after the Inter-Zonal Congestion Management process for Active Zones and before the Intra-Zonal Congestion Management process, or, whether it will take place simultaneously with

another Congestion Management process and (2) the precise manner in which these costs are calculated.

5. The Default Usage Charge

August 15th Filing

The submission of Adjustment Bids to the ISO for Congestion Management is voluntary. This gives rise to the possibility that during certain hours in the Day-Ahead or Hour-Ahead Markets the Adjustment Bids submitted may be unusable or inadequate to enable the ISO to schedule Inter-Zonal Interface capacity on an economic basis. In this situation, "the ISO will assume a decremental bid of zero and an incremental bid equal to the highest Hourly Ex Post Price for the Zones on either side of the Inter-Zonal Interface for the relevant Settlement Period." 260/ The Usage Charge in this instance -- the Default Usage Charge -- will be calculated based on these values and transmission capacity will be allocated on a pro-rata basis among Scheduling Coordinators that did not submit Adjustment Bids.

Contested Issues Identified by the ISO/PX

According to DWR, the Default Usage Charge, which will be based on the incremental bid equal to the highest ISO real time Zonal Imbalance Energy price for the Zones on either side of the Inter-Zonal Interface, may exceed actual costs incurred to relieve Congestion and constitutes an unreasonable penalty. 261/ DWR states that the Usage Charge specified in Section 7.3.1.1 of the ISO Tariff more accurately reflects the costs of managing Congestion. DWR argues that the Default Usage Charge may be increased one hundred fold over the Usage Charge specified in Section 7.3.1.1 of the ISO Tariff. The Default Usage Charge is not justified when the ISO finds "inadequate or unusable Adjustment Bids have been submitted." 262/ Thus, it argues that the Commission should require the ISO to base the Default Usage Charge on the previous Usage Charge Settlement periods in which correct charges were developed in like circumstances, plus a small (5 or 10 percent) increase to cover any additional costs. 263/

260/ ISO Tariff, August 15, 1997, Section 7.3.1.3.

261/ DWR at 18.

262/ DWR at 20.

263/ Id.

June 23, 1997 ISO/PX Reply Comments

In response to DWR, the ISO/PX contend that the Congestion

Management provisions in the ISO Tariff cannot be effective if parties do not submit adequate or usable Adjustment Bids. Although the Default Usage Charge could be much higher than the normal Usage Charge, it is not unreasonable. It implicitly assumes a decremental bid of zero and an incremental bid equal to or greater than the price of Energy in the zone. If the participant's actual value of use of the constrained transmission is less than this, the Scheduling Coordinator will have an incentive to submit adequate and usable Adjustment Bids. This will avoid extended use of pro-rata allocation and gaming attendant to pro-rata allocation rules, and restore an economically rational allocation process. 264/

September 2, 1997 Comments

DWR requests modification of the Default Usage Charge, which is based on energy prices rather than on Congestion Management, and is more costly that the Usage Charge specified in Section 7.3.1.1 of the ISO Tariff. DWR states that the explanations of the Default Usage Charge in the August 15 Filing do not limit its impact or cure the problems of such a punitive fee for congestion.

Commission Response

We accept the ISO's proposal for establishing a Default Usage Charge. The ISO's proposal creates incentives for market participants to submit Adjustment Bids that reflect their respective values for Inter-Zonal transmission. This incentive is important if the ISO is to be able to use Adjustment Bids to allocate Inter-Zonal transmission capacity effectively. A market participant should elect not to submit Adjustment Bids only if the participant desires Inter-Zonal transmission service regardless of the Usage Charge. The lower Usage Charge that would result under the DWR proposal would reduce the risk that a market participant that does not submit Adjustment Bids would pay a higher price for transmission service than its value of transmission. Thus, the incentive to submit Adjustment Bids would be lower and the likelihood of an inefficient outcome would be greater. Since the ISO's proposal results in a higher price for Inter-Zonal transmission, it provides stronger incentives for market participants to submit Adjustment Bids that reflect their respective values for Inter-Zonal transmission.

264/ ISO/PX June 23, 1997 Reply Comments at 234.

The Commission directs the ISO to clarify the procedures that will be used when allocating transmission capacity on a pro-rata basis. In particular, the Tariff should specify whether the ISO will maintain balanced schedules for each Scheduling Coordinator when it reduces a Scheduling Coordinator s Generation due to insufficient transmission capacity.

D. Transmission Rights

In the July 30 Order, the Commission required the ISO to file a plan for transmission rights by June 30, 1998 and to implement this plan on January 1, 1999. The Commission afforded the ISO flexibility in developing this plan, recognizing that transmission service in the restructured California will be based on a different set of rights and relationships than those that underlie the Pro Forma Tariff.

September 2, 1997 Comments

Nymex, and ECI note that in response to the July 30 Order, the ISO and PX have included among their ISO Implementation issues a reference to the need to implement firm transmission rights as: Absence of Transmission Congestion Contracts: Prepare proposal for filing by June 30, 1998 to comply with July 30, 1997 Order. 265/ Nymex and ECI request confirmation in the Commission s order addressing the substance of the August 15 Filing, that the Commission is not approving a Transmission Congestion Contract (TCC) approach in place of a physical rights approach to transmission rights. 266/

Southern Energy and CCEM argue that it is necessary to develop some form of interim transmission rights now to facilitate development of the new marketplace. Southern Energy and CCEM propose interim transmission rights auctions. CCEM recommends seasonal auctions of rights to use the ISO's inter-zonal interfaces, with proceeds credited to the Participating Transmission Owners in the same way as usage charges. Southern Energy and CCEM propose that transmission rights could be re-sold through the ISO's OASIS in hourly blocks, subject to reversion to the ISO if not exercised within the day-ahead market prior to the start of the congestion management process. 267/

265/ August 15 Filing, Appendix I, Catalogue of Issues, Part II (Issues to Implemented and/or Considered After January 1, 1998).

266/ Nymex at 3-4; ECI at 4-7.

267/ Southern Energy at 6-7; CCEM at 24-27. Enron filed a Request for

(continued...)

CMA and CLECA support the Commission s phased approach to addressing firm transmission rights and oppose any proposals that may suggest placing firm transmission rights into effect as of January 1, 1998. 268/

DWR states that not all financial entitlements associated with firm capacity rights have been identified. DWR argues that these rights must be identified promptly and must be included in the proposal for firm rights to be developed and filed by June 30, 1998. Also, DWR argues that the allocation of usage charge revenues and similar entitlement to Existing Contract holders with firm transmission rights should not be diminished by the

allocation of revenues to holders of so called conditional firm rights, 269/ while final resolution of firm transmission rights is pending.

The CEC requests that the Commission condition implementation of the ISO on the ISO making the June 30, 1998, filing to implement firm transmission rights beginning January 1, 1999, and that January 1, 1999 should be considered the outside deadline. 270/

Commission Response

The Commission clarifies that it is not requiring the ISO to develop Transmission Congestion Contracts (TCCs) in lieu of physical transmission rights. The ISO must develop transmission rights that, 1) enable transmission customers to secure transmission service that is as good or superior to the service under the Order No. 888 Pro Forma Tariff, 2) do not allow participants to withhold transmission capacity from the market, 3) are resellable, and 4) comply with the Commission s ISO Principles.

267/ (...continued)
Rehearing on August 29, 1997 regarding this same issue. Enron state that the lack of firm transmission rights unduly discriminates again bilateral transactions since holders of existing contract rights hol pre-existing long-term firm transmission rights that are grandfather

268/ CMA and CLECA at 1-3.

269/ Conditional firm rights apply to certain types of firm rights PG&E sold on Path 15, that may depend on whether other rights holders use service.

270/ CEC at 15.

The Commission denies EPMI's request for rehearing, as well as Southern Energy s and CCEM s request that some form of interim transmission rights be developed now. As the Commission stated in the July 30 Order, we are persuaded that the delay in developing firm transmission rights is necessary so that other features of the restructured market can be implemented on the ISO Operations Date.

To the extent that there are unidentified financial entitlements associated with firm capacity rights, DWR should pursue this matter through the ISO.

B. Transmission Expansion and Planning

In our July, 30 Order we approved the transmission and

expansion process outlined by the ISO. Specifically, we stated that, "[t]he initial transmission expansion proposal establishes a realistic and workable regime." 271/ The March 31, 1997, Phase II filing proposed an initial transmission system expansion process that relies on the obligation of each Participating Transmission Owner to construct all transmission additions and upgrades within its service territory. Under the ISO/PX Trustee's proposal, while the ISO would not have the unilateral right to order an expansion, the ISO will be free to propose any transmission expansion it deems necessary for reliability purposes. A Participating Transmission Owner will be obligated to construct such transmission facilities, subject to appropriate appeals.

Under the ISO/PX's proposal all participants will have the right under the ISO Tariff to propose economic expansions and to become a Project Sponsor. 272/ In the event a dispute arises over the financing of a transmission project or a Participating Transmission Owner fails to act on the Project Sponsor's request, the Project Sponsor may submit its proposal to the ISO ADR Procedure for a determination of need. Our July 30, 1997, order found that certain aspects of the ISO/PX's proposal lacked clarity. Specifically, we noted that the ISO Tariff fails to provide how parties who are assessed the cost of an expansion will be able to benefit from such an investment. We directed the ISO to incorporate in the ISO Tariff a provision whereby either Project Sponsors or specifically identified beneficiaries of a transmission expansion project are entitled to receive their pro rata share (based on ownership) of the Usage Charge and Wheeling

271/ July 30 Order, 80 FERC at 61,433.

272/ A Project Sponsor is a Market Participant or a Participating Transmission Owner that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff

revenues associated with the expansion facilities. We recognized, however, that the issue of cost allocation for transmission expansion projects will be fact-specific and will be resolved on a case-by-case basis.

Contested Issues as Identified by the ISO/PX

We addressed many of the issues raised by the parties with regard to the ISO/PX's proposed transmission expansion and planning process in our July 30 Order. Certain issues were not addressed. We address those issues here.

LADWP contends that the ISO should implement a single, ISO-wide rate as a permanent pricing methodology. LADWP supports the notion that identified beneficiaries should pay the cost of transmission expansions, as opposed to payment by the Transmission Owner that constructs an expansion. LADWP recommends that the ISO adopt a single, ISO-wide rate as a permanent pricing methodology in order to recover the capital

cost of transmission expansion projects and to avoid the complexity of identifying the beneficiary. 273/

Facilities Studies

SoCal Edison contends that Participating Transmission Owners should have the exclusive right to perform Facilities Studies. SoCal Edison claims that since all Transmission Owners are required to build, own, maintain, and operate a facility, it is unreasonable for the Participating Transmission Owner to be required to rely on a third-party to perform the facility study. SoCal Edison states that the Commission's Pro Forma Tariff places the obligation and the authority to perform facilities studies solely on the transmission provider. 274/ In addition, SoCal Edison questions whether it is appropriate for Market Participants to be provided with information relating to reliability projects under Section 3.2.1.2 of the ISO Tariff since reliability expansion projects are likely to be sponsored by the ISO. 275/

Southern Cities/Azusa and Banning state that disputes related to a Facilities Study Agreement must be subject to ADR

273/ LADWP at 27.

274/ SoCal Edison at 24-25.

275/ Id. at 23-24.

and the Commission's review. 276/ In addition, Southern Cities/Azusa and Banning contend that the cost responsibility for a study necessary for RTG and WSCC coordination should track the cost responsibility for the project.

June 23, 1997, ISO/PX Reply Comments

In response to LADWP's recommendation, the ISO/PX state that an ISO-wide rate undermines the locational price signals of zonal energy pricing and congestion charges. The ISO/PX argue that a system-wide transmission rate would require the consumers in a lower-priced zone to help pay for an expansion that will raise their cost of electricity. The ISO/PX state that this is clearly neither equitable nor an efficient expansion signal. The ISO/PX state that under those circumstances consumers whose price will increase will redouble their efforts to block construction. The ISO/PX conclude that initially, an ISO-wide rate is a bad idea that undermines market efficiency and is contrary to the cost causation principle which LADWP indicates that it supports.

With regard to SoCal Edison's recommendations, the ISO/PX state the Participating Transmission Owners must perform the Facilities Studies that the ISO or the Market Participant wants

to be carried out, particularly in relation to scope and assumptions. The ISO/PX emphasize that special care has been taken in both the ISO Tariff under Section 3.2.3 and the Transmission Owner Tariffs under Section 9.1.1 to ensure that the Participating Transmission Owner does not withhold information and that it does not offer a Facilities Study Agreement with its own ideas as to scope, content and assumptions. In response to SoCal Edison's concern with regard to providing information to all Market Participants about reliability projects, the ISO/PX state that the provision is useful to enable Market Participants to participate in the coordination envisioned in Section 3.2.1.2 of the ISO Tariff. In addition, the ISO/PX state that Market Participants may want to consider or question the need for the project if they are likely to have to pay for it.

The ISO/PX state that Southern Cities/Azusa and Banning make a good point that the Facilities Study Agreement must be subject to ADR and the Commission's review. In addition, the ISO/PX state that Southern Cities/Azusa and Banning's suggestion that the cost responsibility for a study, required as part of the RTG and WSCC coordination process, should track the cost responsibility for the project is sensible. The ISO/PX argue that the study costs should be small by comparison with the cost of the project. The ISO/PX state that it could accept the principle with respect to facilities that are ultimately

276/ Southern Cities/Azusa and Banning at 11; Joint Comments at 60.

constructed, and recover the cost of studies which do not result in construction through the Grid Management Charge.

Request for Rehearing

On August 29, 1997, Turlock filed a Request for Rehearing and Motion for Clarification with respect to our July 30, Order. Among other things, Turlock states that the Commission misinterpreted Order Nos. 888 and 888-A and FPA section 211 in finding that the initial transmission expansion and planning process is reasonable. Turlock states that the public interest standard under section 211 of the FPA requires that transmission expansion projects must not unreasonably impair reliability and that the transmitting utility must be fully and fairly compensated for the cost of the transmission expansion. Turlock states that under section 211, applicants for wheeling must satisfy both parts of that test. Turlock states that the ISO's test, which the Commission approved, differentiates between reliability and economically driven expansion projects and is therefore contrary to the public interest standard. In addition, Turlock states that the Commission should clarify that the ISO's proposal must satisfy the cost recovery standards of section 211 of the FPA. Turlock states that Section 3.2.1.1 of the ISO Tariff provides for the "full cost" recovery of transmission expansion projects, and that this is not necessarily consistent with the "just and reasonable" standard of section 211(a) of the FPA. Finally, Turlock objects to the Commission's acceptance of

the ISO's mandatory ADR procedure. Turlock argues that the ISO's mandatory ADR procedure supplants the dispute resolution procedures under the FPA. Turlock requests that the Commission make the ISO's ADR procedure voluntary.

September 2, 1997 Comments

DWR requests that Section 3.2.8 of the ISO Tariff be amended to specify how less costly alternatives to transmission expansion will be priced. 277/ DWR points out that providers of lower cost alternatives to transmission expansions or upgrades have a right to notice of the price to be paid for such alternatives.

PG&E opposes the revision to ISO Tariff Section 3.2.7.3 in the August 15 filing because the calculation of the share of Wheeling revenues attributable to the transmission addition or upgrade is too prescriptive and is inconsistent with ISO Tariff Section 7.1.4.3 (disbursement of Wheeling Revenues between Participating Transmission Owners). According to PG&E, ISO Tariff Section 7.1.4.3 reflects a negotiated compromise among

277/ DWR at 25-26.

competing interests and should not be undermined by the new language. 278/

Redding proposes that the ISO be made the coordinator for all expansion projects. According to Redding, even if Participating Transmission Owners are required to build, they may still delay, impede, or cost-overrun a project they do not fully support. 279/ Under Redding s proposal, the ISO would merely be the central point of contact; it could bid to professional organizations central transmission planning or staffing functions, and the Participating Transmission Owner could still participate in a consulting role.

Commission Response

Regarding LADWP's recommendation to require the ISO to immediately implement a system-wide rate for transmission, we do not find the argument compelling. Although such a system-wide rate may be reasonable, the method proposed here, intended to give efficient price signals for transmission expansion, is not unreasonable. Therefore, we reject LADWP's proposal.

We agree with SoCal Edison that Participating Transmission Owners should be obligated to perform Facilities Studies. Because Participating Transmission Owners are well situated to perform facilities studies, we do not agree with Redding s suggestion to use outside organizations to perform this work. Participating Transmission Owners have a working knowledge of their systems and may have performed studies similar to those requested. However, we agree with the ISO that the Participating Transmission Owner should work with the ISO and Market

Participants to establish the scope of and assumptions for the study that are acceptable to all parties. To the extent a party wishes to sponsor an economically driven project, that party should contribute to the assumptions used in that study. We agree with Southern Cities/Azusa and Banning that the cost responsibility for a study should track the cost responsibility for the project. Therefore, since sponsors of a specific project are to pay for the facilities study costs, that party is entitled to have input on the assumptions and scope of the study. In addition, we agree with the ISO that Participating Transmission Owners should make information on reliability-driven projects available to any Market Participant that requests it. To the extent information on a specific project is available through the WSCC or WRTA planning process, the Transmission Owner can direct requesting parties to the WSCC or WRTA. Finally, we agree with

278/ PG&E at 12.

279/ Redding at 31.

the ISO and Southern Cities/Azusa and Banning that Facility Study Agreements should be subject to the ISO's ADR process and Commission review.

We reject Turlock's request for rehearing and grant Turlock's motion for clarification with respect to transmission expansion issues. As we stated in our July 30, Order, the ISO's proposal is not inconsistent with section 211 of the FPA. We agree that transmission expansion proposals must not impair reliability and that a transmitting utility must always be compensated for the cost of an expansion project. However, we disagree that the ISO's proposal to conveniently label a project as either economically driven or reliability driven is inconsistent with the section 211 standard. We regard Sections 3.2.1.1 and 3.2.1.2 (Economically Driven Projects and Reliability Driven Projects) of the ISO Tariff to be convenient methods of identifying the primary project sponsor (Market Participant or the ISO) for transmission expansion projects and for outlining a procedure for determining need and cost responsibility. In either case, all transmission expansion proposals filed with the Commission must satisfy the FPA's just and reasonable standard. As we stated in our July 30 Order, ultimately the issue of cost allocation for transmission expansion projects will be fact-specific and will be resolved on a case-by-case basis.

We also reject Turlock's request to make the ISO ADR procedure voluntary. Due to the limited time and resources of the Commission, we find that it is essential that the parties to the ISO Tariff attempt to resolve their disputes before bringing them before the Commission. However, we note that under Section 13.4 of the ISO Tariff, parties may appeal an arbitration decision to the Commission. Therefore, Turlock's concern that it will be prevented from using the dispute resolution procedures of the FPA is incorrect.

We do not agree with DWR's argument that the ISO Tariff

should be revised to address the pricing of less costly alternatives to transmission expansion such as constrained-on generation, reactive power and interruptible loads. The ISO/PX correctly note that the proposed market structure already provides pricing through Must-Run contracts, Ancillary Services and Intra-zonal congestion pricing for constrained-on generation. The ISO also notes that Generators requested by the ISO to provide reactive power in excess of the standard requirements will be compensated at their opportunity costs. In addition, the ISO correctly points out that under the ISO/PX's proposal, interruptible loads can be utilized to supply Operating Reserves and to supply Supplemental Energy Bids.

We agree with PG&E that the revised language in Section 3.2.7.3 of the ISO Tariff is too prescriptive and that it is premature to adopt a single method for allocating revenues

attributable to transmission upgrades. Accordingly, we order the ISO to delete the phrase "(calculated on the basis of the proportion which the capacity of the transmission addition or upgrade bears to the total transmission capacity to which such Wheeling revenues are attributable)." A determination on the proper allocation method for revenues attributable to a specific transmission upgrade will be made at the time the project is initiated.

C. Ancillary Services

Description of the Proposal

In Order No. 888, the Commission concluded that a transmission provider must include the following six ancillary services in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve - Spinning Reserve Service; and (6) Operating Reserve - Supplemental Reserve Service. 280/

In the proposal before us, the ISO will be responsible for ensuring that sufficient Ancillary Services are available to manage the reliability of the ISO controlled grid. 281/ The ISO identifies six ISO Ancillary Services in the ISO Tariff: Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support, and Black Start capability.

While the ISO Tariff uses similar terminology to Order No. 888 and generally conforms with its ancillary services requirements, the ISO Ancillary Services are not simple one-to-one matches with those identified under Order No. 888. 282/ The ISO/PX have proposed a comprehensive industry restructuring that has evolved in the post Order No. 888 environment. It includes a design for a new spot market and direct access. We will accept the proposed ISO Ancillary Services because the actions required by the ISO and the obligations under the tariff indicate that the ISO will provide all necessary services. In addition, the ISO and Market Participants will seek to develop additional

280/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,703.

281/ ISO Tariff, Section 2.5

282/ For example, the ISO tariff does not include Scheduling, System Cont and Dispatch Service as an ancillary service in its tariff. However the ISO will provide a comparable service with the costs allocated t the Scheduling Coordinators in proportion to the energy they schedul each month. The ISO filed a charge to recover these costs in Docket ER98-211-000.

categories of these unbundled services over time as the operation of the ISO controlled grid matures. 283/

1. Auctions and Prices

Procuring Ancillary Services

The ISO would contract for the two Ancillary Services of Voltage Support and Black Start Capability annually (or for another time period, if the ISO finds it economically advantageous). The ISO would also contract for Voltage Support on a daily or hourly basis as required for reliability purposes. The remaining four Ancillary Services may be self-provided by Scheduling Coordinators. 284/ Those not self-provided would be competitively procured by the ISO.

The ISO would operate a Day-Ahead and Hour-Ahead market to procure the Ancillary Services of Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. 285/ It would purchase Ancillary Service Capacity for these services at least cost to End-Use Customers consistent with maintaining reliability. Scheduling Coordinators may bid the same capacity into any or all of these Ancillary Service markets. The ISO would evaluate bids sequentially in the following order: Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. Capacity accepted in one market would not be passed on to another market, while any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates.

Bids for Day-Ahead Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves must be received by 10 am on the day prior to the Trading Day. Bids would include information for each of the 24 settlement periods of the Trading Day. Bids for these four services for the Hour-Ahead market must be received at least two hours prior to the settlement period. 286/ In each of the auctions for these services, the ISO would determine winning bids based on the total bid, which is defined as the bid capacity multiplied by the sum of the reservation bid plus the forecast Usage Charge. The price payable for each category of capacity (i.e., Regulation, Spinning Reserves, etc.) would be the zonal market clearing price for the settlement period, determined as the highest winning capacity bid in the zone for the settlement period. 287/

283/ ISO Tariff, Section 2.5.1

284/ ISO Tariff, Section 2.5.1.

285/ ISO Tariff, Section 2.5.8.

286/ ISO Tariff, Section 2.5.10.1.

287/ ISO Tariff, Section 2.5.14.

The forecast Usage Charge portion of the total bid would be the same for all bidders competing to supply a given type of Ancillary Service in a given zone and for a given time period. Thus, under the August 15 proposal before us, the ISO would select bidders with the lowest bids for capacity that meet the technical requirements, including location and operating capability. 288/

Under the August 15 proposal, Voltage Support would be competitively procured from available sources (including loads) through contracts. Payments to public utilities to compensate for Voltage Support would be capped at FERC-authorized cost-based rates unless the Commission authorizes otherwise. 289/

The ISO would procure Black Start capability competitively through contracts. The ISO would evaluate bids for Black Start capability based on the product of each bidder's reservation bid multiplied by its offered capacity. The price paid by the ISO to winning bidders would be the highest accepted reservation fee in the applicable settlement period. 290/

The charges assessed to users of Ancillary Services to cover the ISO's costs of procuring Ancillary Service capacity are described in ISO Tariff Section 2.5.28. The ISO would determine a separate hourly user rate for each Ancillary Service for each settlement period purchased in the Day-Ahead market and in the Hour-Ahead market. These rates would be charged to Scheduling Coordinators on a volumetric basis applied to all demand not covered by a self-provision arrangement.

Imbalance Energy

Capacity for Regulation and the three categories of Reserves (Spinning, Non-Spinning, and Replacement) is procured by the ISO to ensure (among other reasons) that adequate capacity is available to provide Imbalance Energy so that aggregate generation always matches aggregate load in real time. However, Imbalance Energy may be procured by the ISO not only from generators providing capacity for Regulation and Reserves, but also from other generators

288/ The proposal before us is different in certain respects from the proposal filed in Phase I for evaluating bids for ancillary services (which was part of the conceptual framework that we accepted in our November 26 Order; see 77 FERC at 61,808), the details of which were described in the ISO's March 31, 1997 filing. Under that proposal, ISO would receive two-part bids for ancillary services: a capacity p bid for being available, and an Energy price bid for producing Energ from the capacity. The ISO would select bidders with the lowest expected total cost of each bidding resource, based the capacity pri bid added to the Energy price bid multiplied by the probability of producing Energy. See the ISO Phase I Filing, April 29, 1996, pp. 5 56, and Appendix D; and March 31, 1997 Filing, ISO Tariff Sections 2.5.14, 2.5.15, 2.5.16, and 2.5.17.

289/ ISO Tariff, Section 2.5.18.

290/ ISO Tariff, Section 2.5.19.

with available capacity in real time that have submitted Adjustment Energy Bids and Supplemental Energy Bids. The ISO will stack all available sources of Imbalance Energy in merit order of their respective Energy Bids. (When transmission congestion exists, the ISO may develop separate stacks for each congestion area.) Scheduling Coordinators electing to self-provide Ancillary Services would submit a Proxy Bid, used by the ISO to position the resource in the merit order for real time Dispatch. 291/ As Imbalance Energy becomes needed in real time, the ISO will dispatch the available generation with the lowest Energy Bids. Conversely, if the ISO is required to reduce Energy output to match aggregate generation and load, the ISO would direct generating units and system resources to reduce Energy output in descending order of Energy Bids. 292/

ISO Tariff Section 2.5.23 describes pricing for Imbalance Energy. The ISO would establish prices for Imbalance Energy for two time intervals: (1) the Five Minute Ex Post Price and (2) the Hourly Ex Post Price. The Five Minute Ex Post Price would equal the bid of the marginal generating unit, load, or system resource dispatched by the ISO to reduce demand or increase or decrease Energy in each five minute period. The Hourly Ex Post Price in each zone would equal the Energy weighted average of the 12 Five Minute Ex Post Prices in the zone.

Under ISO Tariff Section 2.5.27, the ISO would operate a daily settlement function for Ancillary Services. The prices paid to generators supplying Imbalance Energy from Ancillary Service capacity are described in ISO Tariff Section 2.5.27. Initially, all Ancillary Service providers supplying Imbalance Energy would receive the Hourly Ex Post Price for the applicable hour in which the Energy is generated. At an as-yet unspecified future time, the Five Minute Ex Post Price would apply. That is, all Ancillary Service suppliers of Imbalance Energy (except those supplying Imbalance Energy from Regulation capacity) would eventually receive the applicable Five Minute Ex Post Price for Imbalance Energy generated during each separate five minute period.

Under ISO Tariff Section 11.2.4, the ISO would calculate, account for and settle Imbalance Energy in the real time market attributable to participants other than generators with Ancillary Service capacity dispatched by the ISO for each settlement period and zone. The ISO would calculate for each Scheduling Coordinator, for each hour, and for each zone the difference between its actual and scheduled Energy Generation or Demand. This Energy imbalance between actual and scheduled Generation or Demand would be settled out at the Hourly Ex Post Imbalance Energy price. If the Energy imbalance is a net supply into the grid, the imbalance would be deemed a sale of Energy to the ISO, and the Scheduling Coordinator would receive the applicable Hourly Ex Post Price for that Energy. If the Energy imbalance is a net withdrawal from the grid, the imbalance would be deemed a purchase of Energy from the ISO, and the Scheduling Coordinator would pay the ISO the applicable Hourly Ex Post

291/ ISO Tariff, Section 2.5.30.6.

292/ ISO Tariff, Section 2.5.22.

Price for that Energy. In addition, Scheduling Coordinators whose generators fall below their schedules or whose demand exceeds their schedules would be allocated a share of the cost of Replacement Reserve. Finally, the ISO intends to develop protocols and procedures for monitoring persistent intentional excessive imbalances by Scheduling Coordinators, and for imposing appropriate sanctions and/or penalties to deter such behavior.

Phase-In of the Ancillary Services Market

The market for Ancillary Services would be phased-in in three respects. 293/ The first concerns the settlement price for Energy dispatched from Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. As noted above, initially, providers of Energy from these sources would receive the Hourly Ex Post Price, which is an average of the 12 five-minute ex post prices for the applicable hour in which the Energy is produced. At an as-yet unspecified future time, and after giving 30 days notice on WEnet, providers of Energy from these sources would receive the applicable five-minute ex post price for Energy provided in the applicable five-minute period. The five-minute price will be determined as the bid price of the marginal resource accepted by the ISO for dispatch during the applicable five-minute period. 294/

Second, the ISO would initially incorporate a forecast Usage Charge into its Ancillary Service bid evaluations to evaluate Ancillary Service bids across zones when congestion is present. Later, after giving 30 days notice on WEnet, the ISO shall determine the applicable usage charge.

Third, public utilities must initially submit bids for Ancillary Services capped at cost-based rates, unless FERC authorizes different pricing. Public utilities without market-based rate authority for Ancillary Services from the Commission will not be paid above their cost-based bid for the Ancillary Service even if the relevant market clearing price is higher. However, if the Commission authorizes a rate in excess of the cost-based rate, the excess would be dealt with in accordance with the rules of the utility's Local Regulatory Authority.

Public Comments

TURN/UCAN contend that the proposed PX Activity Rules should also be applied to non-PX markets, including Ancillary Services and Imbalance Energy. 295/ The ISO/PX respond that the Activity Rules for the PX were developed to address a problem that does not apply to Ancillary Service and Imbalance

293/ ISO Tariff, Section 2.5.7.

294/ ISO Tariff, Appendix A.

295/ TURN/UCAN Comments, June 6, 1997 at 113-114.

Energy markets. 296/ The PX Activity Rules were designed to ensure that an auction with multiple rounds of bidding would converge to a technically feasible and efficient solution in an orderly and timely manner. However, the ISO/PX point out, the Ancillary Services and Imbalance Energy markets do not involve multiple bidding rounds, and thus have no need for PX-type Activity Rules.

September 2, 1997 Comments

LADWP opposes the proposal to initially pay ancillary service providers the average of the twelve Five Minute Ex Post Prices for the hour in which they supply imbalance Energy. 297/ In LADWP s view, this proposal would guarantee that some generators would be paid less than their bid price. LADWP recommends that until the ISO can provide Five Minute Ex Post Prices, the ISO should pay the highest Five Minute Ex Post Price for each applicable hour.

LADWP also opposes the proposal in Section 11.2.4.1 that the ISO develop protocols for monitoring excessive Energy imbalances and that permits the ISO to impose sanctions or penalties, for the following reason. 298/ Market signals and economic consequences are sufficient to ensure that the market properly values Energy imbalances services. However, if the Commission disagrees, the word intentional should be deleted, since the intent of the Scheduling Coordinator is not relevant to the effect of the imbalance.

SoCal Edison recommends that the ISO not be permitted to impose penalties for excessive imbalances on PX participants under ISO Tariff Section 11.2.4.1, until the PX Hour-Ahead Market is functional. 299/ SoCal Edison notes that the delay in implementing the PX Hour-Ahead Market due to software constraints will force PX market participants to be significantly more reliant on Imbalance Energy in the ISO s Real Time Market, since there will not be a PX Hour-Ahead Market to allow for the correction of forecasting errors, which can be significant over a 24-hour period.

TURN/UCAN argue that the ISO/PX s August 15 response to Staff s data request No. 31 did not demonstrate that the approach to Ancillary Services would achieve efficiency. 300/

SoCal Edison contends that charges for ancillary services should reflect actual production and consumption. Although Section 2.5.1 of the ISO Tariff refers to procurement of ancillary services in real time, SoCal Edison notes

296/ ISO/PX Reply Comments, June 23, 1997 at 296.

297/ LADWP at 24-25.

298/ LADWP at 36-37.

299/ SoCal Edison at 18-19.

300/ TURN/UCAN at 32.

that Sections 2.5.27 and 2.5.28 of the ISO Tariff fail to address payment or billing for ancillary services beyond the arrangements for the Day-ahead and Hour-ahead Markets. According to SoCal Edison, the revised language in Section 2.5.28 of the ISO Tariff would encourage Scheduling Coordinators and customers to underestimate scheduled demand, because charges would be based on scheduled demand, rather than actual use. SoCal Edison argues that Scheduling Coordinators must be charged the ISO s real time costs for the difference between actual and scheduled usage in the Day-Ahead and Hour-Ahead Markets. SoCal Edison states that ISO Tariff Section 2.5.27 contains the same defect. 301/

Southern Energy contends that the ISO proposal to pay generators providing supplemental Energy based on an hourly average ex-post price, rather than the marginal 5-minute ex-post price bid, during the initial stage of operations, creates a risk that will drive up bid prices, increasing the cost of Imbalance Energy to all market participants. 302/

The California Commission reserves the right to comment on details of the ancillary services proposals as they are filed. Also, the California Commission requests more information regarding how the forecasted Usage Charge would be developed. 303/

The California Commission supports the proposed revision to ISO Tariff Section 2.5.7.3, which makes clear that until the Companies demonstrate that they lack market power in each ancillary services market, they should be paid no more than the cost-of service based tariff rate for each service. However, the California Commission requests deletion of the portion of the revised provision which states, ". . ., provided that if FERC has authorized a rate in excess of the cost-based rate, the excess shall be dealt with in accordance with the rules of the utility's Local Regulatory Authority." The California Commission states that this language is unnecessary, premature and confusing. 304/

Commission Response

We note LADWP's concern that under the ISO s proposal to initially pay Ancillary Service providers of Imbalance Energy the Hourly Ex Post Price, which is the average of the 12 Five Minute Ex Post Prices for the hour, some providers would be paid less than their bid price. We will deny LADWP's request and accept the ISO's staging proposal for pricing Imbalance energy from Ancillary Service providers. However, the ISO/PX has offered no explanation why the ISO is unable to pay Ancillary Service providers of

301/ SoCal Edison at 12-13.

302/ Southern Energy at 6.

303/ California Commission at 16-17.

304/ California Commission at 17-18.

Imbalance Energy the Five Minute Ex Post Price on the date when it begins operations. Indeed, it appears that the ISO must be able to calculate the Five Minute Ex Post Price on the date when the ISO begins operations, because

the Five Minute Ex Post Prices are used to calculate the Hour-Ahead Ex Post Price. 305/ Therefore, we direct the ISO in its compliance filing to explain why it must stage the use of the Five Minute Ex Post Price to compensate Ancillary Service Providers of Imbalance Energy. In addition, consistent with our rulings on other staged features, we direct the ISO to delete the provisions of the ISO Tariff posted on WEnet regarding compensation for Imbalance Energy that will not be in effect on the date that the ISO begins operations. The ISO may file to implement compensation at the Five Minute Ex Post Price 60 days before it is ready to implement this provision.

SoCal Edison recommends that the ISO not be permitted to impose penalties for excessive imbalances on PX participants until the PX Hour-Ahead Market is functional. LADWP entirely opposes the ISO's proposal to permit the ISO to impose sanctions or penalties on individual Scheduling Coordinators for intentional, excessive imbalances. In LADWP's view, market signals and economic consequences are sufficient to ensure that the market properly values Energy imbalances services.

The ISO has not filed specific sanctions or penalties for imbalances with us. The ISO may file with us to propose specific sanctions or penalties that it deems necessary and appropriate to address imbalance problems that may arise in the future. 306/ However, the ISO may not impose sanctions or penalties for imbalances without our prior approval. We encourage the ISO to monitor the levels of imbalances, as it proposes in Section 11.2.4.1 of its Tariff. The ISO may propose additional remedial measures through appropriate filings with us if experience suggests they are needed.

We will not address at this time TURN/UCAN's recommendation that the PX's Activity Rules be applied to the Ancillary Services and Imbalance Energy markets. We do not know what the final PX Activity Rules will be, since they have not yet been filed with us. Therefore, we cannot determine whether they should be applied to other markets such as the Ancillary Services and Imbalance Energy markets. TURN/UCAN may refile its recommendation when the PX Activity Rules are filed with us.

We note TURN/UCAN's concern regarding the efficiency of the method for evaluating Ancillary Service bids. The August 15 Filing proposed two-part bids -- for capacity and for producing Energy -- for Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves, but would evaluate the bids based only on the capacity bid. Participants submitting the lowest capacity bids, no matter how high their Energy bids, would always be chosen in preference to those submitting higher capacity bids. The ISO/PX argue in

305/ ISO Tariff Appendix A, Master Definitions Supplement, Original Sheet 301.

306/ There are, of course, different ways to address the issue of imbalan Penalties and sanctions are one option; market mechanisms are anothe

their August 15 response to the Staff Data Request that the new approach to the evaluation of Ancillary Service bids may not necessarily minimize the overall cost of Ancillary Services (including the Energy component) to the ISO, but that the new approach does encourage and promote overall cost minimization across all markets for Energy and Ancillary Services. 307/

We are not fully persuaded by the ISO/PX's assertion regarding the

overall cost minimization of the new approach. We will accept the August 15 bid evaluation proposal specified in the ISO Tariff, but will require that the ISO file a report by January 1, 1999 that explores the issue of bid evaluation further. This will allow the ISO and market participants to gain experience and data under the proposed method. The report should include information for the nine months of operation on the range of capacity and Energy bids, and the market clearing capacity prices for Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. After we review the report, we may revisit the bid evaluation issue.

Charges for Ancillary Services

SoCal Edison comments that the ISO Tariff fails to assess Scheduling Coordinators for the costs of procuring Ancillary Services caused by real time generation and consumption. Since charges for Ancillary Services are based only on scheduled (and not real time) demand, SoCal Edison argues, Scheduling Coordinators have an incentive to understate their scheduled demand. We agree in part with SoCal Edison. SoCal Edison's comment does not acknowledge that a Scheduling Coordinator's discrepancies between generation and demand that occur in real time will result in charges for Replacement Reserves, under Section 11.2.4.1. So to the extent that a Scheduling Coordinator's real time transactions deviate from its schedule in a way that results in an imbalance between its generation and its load, the Scheduling Coordinator will face an additional charge for Ancillary Services.

However, a Scheduling Coordinator could escape additional charges for Ancillary Services by deviating from its schedule in a way that does not result in a discrepancy between generation and load. For example, a Scheduling Coordinator could schedule 200 MW to be generated and consumed, but its real time generation and load could be 250 MW. 308/ Under the ISO Tariff, the Scheduling Coordinator's increase in real time transactions compared to its schedule would not result in any additional charge for Replacement Reserves or other Ancillary Services, even though the ISO would need to procure additional Replacement Reserves to comply with NERC guidelines. We direct the ISO to modify its Tariff so that Scheduling Coordinators will pay the additional costs of Ancillary Services caused by real time changes in their demand (relative to scheduled demand). We expect the ISO to monitor

307/ August 15 Filing, Appendix III, Response to Question No. 31, pp. 19-

308/ We note that Sections 2.2 and 5 of the ISO Tariff do not allow generators to unilaterally deviate from their schedules without ISO notification.

scheduling practices. We encourage the ISO to propose penalties or market mechanisms to promote good scheduling practices by Scheduling Coordinators that are necessary to ensure reliability and avoid cost shifting.

The Forecast Usage Charge

We agree with the California Commission that the filing has not yet stated the details of how the forecast Usage Charge, used in the Bid Evaluation for Ancillary Service auctions described in Section 2.5, will be developed. We anticipate that the ISO's protocols, to be filed by November 1,

1997, will provide the details.

Disposition of Certain Ancillary Service Revenues

We agree with the California Commission's request to delete the portion of Section 2.5.7.3 of the ISO Tariff that reads ... provided that if FERC has authorized a rate in excess of the cost-based rate, the excess shall be dealt with in accordance with the rules of the utility's Local Regulatory Authority. Since we are not approving market based rates for Ancillary Services for the three California IOUs, we agree with the California Commission that the language is unnecessary, premature, and confusing. Moreover, other public utilities without any local regulators, i.e., strictly wholesale market sellers, may participate in these markets.

In addition, Section 2.5.7.3 makes reference to FERC-jurisdictional utilities in discussing the phase-in of market based prices. The Commission does not have authority under section 205 of the FPA to regulate the rates for Ancillary Services of nonpublic utilities, such as municipally-owned utilities. Therefore, we direct the ISO to replace the phrase FERC-jurisdictional utilities everywhere it appears in Section 2.5.7.3 with the phrase public utilities under the FPA.

Standards and ISO Control of Resources

As the Control Area Operator, the ISO is responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. Section 2.5 of the ISO Tariff requires that all generators and loads that provide ancillary services be under the direct control of the ISO. Moreover, all Generating Units, Loads and System Resources that provide ancillary services must be certified by the ISO as having satisfied its technical requirements for providing a particular Ancillary Service. The ISO states that this is necessary in order to ensure the safe and reliable operation of the system. The ISO commits to enforce reliability criteria no less stringent than those mandated under the WSCC Minimum Operating Reliability Criteria (MORC) and NERC standards. The ISO states that the ISO's Technical Advisory committee will periodically review ISO

Controlled Grid Operations in order to determine if Ancillary Service standards need to be revised. The Technical Advisory Committee will also conduct such reviews to accommodate revisions to WSCC and NERC standards.

Contested Issues as Identified by the ISO/PX

TANC contends that the ISO should have dispatch authority over the Ancillary Services self-provided by a Metered Subsystem only in emergency conditions. 309/

June 23, 1997 ISO/PX Reply Comments:

In response, the ISO/PX states that it does not agree that it may only dispatch self-provided Ancillary Services during emergency conditions. The ISO must have the right to dispatch those Ancillary Services, whether self provided or not, in real time in order to effectively discharge its duties in managing the ISO Controlled Grid. The ISO, as Control Area Operator, is responsible for the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. Because the ISO needs to be able to prevent emergency conditions from arising, it is essential that the ISO have dispatch rights over all committed sources of Ancillary Services in real time, whether or not they are self-provided by a Scheduling Coordinator. Self-provision of Ancillary Services does not mean self-dispatch of Ancillary Services, particularly when the ancillary services provider is not also a control area. In this case, the ISO/PX state that all parties agree that a MSS is not a Control Area. Dispatch of Ancillary Services is coordinated by the ISO as operator of the ISO Controlled Grid. 310/

September 2, 1997 Comments

BPA requests that Section 2.5.16 (Non-Spinning Reserves) of the ISO Tariff be clarified to conform with WSCC standards. According to BPA, that section requires a provider of Non-Spinning Reserve to include in its bid the MW capability available within ten minutes. However, BPA states, in evaluating bids, the ISO will select a generating unit to provide Non-Spinning reserves if the Generating Unit s capacity does not exceed the Generating Unit s ramp rate times ten minutes. BPA contends that this procedure ignores the time necessary to

309/ TANC at 76.

310/ ISO/PX June 23, 1997 Reply Comments at 178.

synchronize a unit that is off-line when access to the reserves is requested. 311/

BPA also contends that the bid evaluation process for Replacement Reserves under ISO Tariff Section 2.5.17 should be corrected. BPA notes that while Replacement Reserves are defined as generating capacity that can ramp to a specified load within 60 minutes, Section 2.5.17 incorrectly requires a shorter 10 minute ramp rate. 312/

BPA recommends that Section 2.5.18 of the ISO Tariff be modified to clarify that the ISO may obtain voltage support from any on-line Generating Unit connected to the ISO grid. According to BPA, this would ensure that the ISO has adequate access to voltage support. BPA asserts that the provision as now written implies that the ISO will purchase voltage support only from Generating Units that have submitted Adjustment Bids. 313/

BPA recommends that the definition of Spinning Reserves, as

contained in Appendix A, Master Definitions Supplement, be modified. According to BPA, the definition should include the portion of unloaded synchronized generating capacity that is immediately responsive to system frequencies and that is capable of being loaded in ten minutes and that is capable of running for at least two hours, consistent with the WSCC definition of Spinning Reserve. 314/

Redding raises a voltage support concern over the accuracy of metering on its system. Specifically, Redding states that Section 2.5.3.4 of the ISO Tariff, which requires all loads connected to the ISO Controlled Grid to maintain a specific power factor, is not technically practical unless the load is radially connected to the ISO Controlled Grid. Redding contends that where load is connected to the ISO Controlled Grid at two or more interconnection points, as is likely with a UDC or MSS, the ISO would measure a decrease in load at certain interconnection points (and a corresponding worsening of the power factor) due to flows from one interconnection point to the other over the distribution system. Redding contends that the proper way to

311/ BPA at 17.

312/ BPA at 18.

313/ Id.

314/ BPA at 21.

address this concern is to net the recorded meter flows but that the ISO Tariff does not address this issue. 315/

PECO argues that the August 15 Filing gives the ISO excessive direct control over Scheduling Coordinator resources. According to PECO, this precludes Scheduling Coordinators from utilizing a portfolio of resources and from managing or self-providing its own ancillary services, inter-zonal transmission capacity, and imbalance energy in the most efficient manner. PECO recommends that the ISO communicate with Scheduling Coordinators and that Scheduling Coordinators then be permitted to manage their own resources in response to ISO requests. 316/

EPUC/CAC recommends that ISO Tariff Section 2.2.1 be amended to require the ISO to procure ancillary services on its own behalf, rather than as agent for Scheduling Coordinators. Similarly, CCEM objects to the ISO control over Scheduling Coordinator resources, and the requirement for direct computer contact and communication between the ISO and each of the Scheduling Coordinator s generators and dispatchable loads. According to CCEM, these requirements are inconsistent with existing communications arrangements, are not necessary for control area operators to operate the grid reliably, and go

beyond the authority required in cases of emergency or technical necessity. 317/

Commission Response

TANC proposes to revise the ISO Tariff to provide that the ISO's authority to control Ancillary Services provided by the Metered Subsystem should exist only in emergency conditions. We agree that the ISO, as the single Control Area Operator, needs real time dispatch rights over all resources committed to provide Ancillary Services. Even TANC's proposed revisions recognize this requirement by allowing the ISO operational control to avoid an emergency situation. We therefore reject TANC's, PECO's and CCEM's recommendations. We also reject EPUC/CAC's recommended change to Section 2.2.1 of the ISO Tariff. The ISO should not be deemed to procure ancillary services on its own behalf since the ISO is not a participant in the market place. The ISO is appropriately securing the necessary ancillary services on behalf of Scheduling Coordinators since it is Scheduling Coordinators who will utilize these services.

315/ Redding at 25-27.

316/ PECO at 3.

317/ CCEM at 13-14.

We note that the ISO Tariff allows a Scheduling Coordinator to become a Metered Subsystem operator if it meets the ISO's technical requirements for metering and communications. We also note that with regard to DWR's requested clarifications, 318/ the ISO/PX states that after January 1, 1998, the Tariff will be revised to clarify the role, responsibility and requirements associated with Metered Subsystems and that this delay is due to the complexity in implementation. Many parties state that allowing a Scheduling Coordinator to qualify as a Metered Subsystem operator is critical. We agree that this is a critical feature and urge the ISO Governing Board to consider this issue with a high priority.

We will require that the ISO Tariff reflect the clarifications recommended by BPA relating to Sections 2.5.16 and 2.5.17 and the definition of Non-Spinning Reserves contained in the ISO Tariff. The ISO has not objected to BPA's proposed revisions and has already committed to follow WSCC standards.

We agree with BPA that the ISO should be able to obtain voltage support from any on-line Generating Unit capable of providing the service. However, we do not believe that the tariff restricts the ISO use to only those Generating Units that have submitted Adjustment Bids. The ISO Tariff permits the ISO to enter into long-term service contracts for Voltage Support from all available sources meeting the technical requirements. We also direct the ISO to cooperate with UDCs such as Redding

with unique metering requirements. The details of a UDC's individual metering requirements should be addressed in its UDC agreement with the ISO. Moreover, we also direct the ISO to address the concerns raised by Redding when evaluating its meter standards.

Self-Provision

The ISO Tariff allows any Scheduling Coordinator to self-provide its allocation, in whole or in part, of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Voltage Support and Black Start may not be self provided under the ISO Tariff and will be procured by the ISO.

Contested Issues as Identified by the ISO/PX

TANC and SMUD argue that Scheduling Coordinators (including, specifically, operators of Metered Subsystems) should be allowed to self-provide Voltage Support and Black Start. These parties argue that they have the capability to provide sufficient Black

318/ DWR September 2, 1997 Comments at 55.

Start in the location necessary to restore their own systems and to contribute to restoring neighboring systems. As to Voltage Support, these parties observe that the Commission has noted that a local transmission provider is often uniquely situated to supply reactive power. Accordingly, they argue there is no logical reason why Scheduling Coordinators that have the technical capability to meet NERC and WSCC reliability criteria for Black Start and Voltage Support should not be permitted to self provide their share of these services. 319/

June 23, 1997 ISO/PX Reply Comments:

The ISO/PX notes that Black Start is not a defined Ancillary Service required by Order No. 888, but it has been included in the ISO Tariff. It is a critical element in the resources which the ISO needs in order to manage the reliability of the ISO Controlled Grid. According to the ISO/PX, Black Start is needed on a system-wide basis in order to restore the whole of the ISO Controlled Grid and not merely that part adjacent to the self-provider of the Black Start capability. The ISO/PX considers it important that the ISO have the discretion to choose what resources can most efficiently restart the system. In light of these factors, the ISO/PX states the ISO Governing Board at its meeting on June 17, 1997, decided not to propose any change to the ISO Tariff at this time. 320/

As to Voltage Support, the ISO/PX notes that the Commission has, under Order No. 888-A, decided to permit a transmission customer to satisfy part of its obligation to purchase Voltage Support from the transmission provider through self-provision or

purchases from generating facilities under the control of the Control Area Operator. 321/ However, the ISO/PX also notes that the Commission has observed that a transmission customer can reduce its requirement for Voltage Support by taking action to install voltage control equipment or by contracting with others who are able to provide such support. 322/

The ISO/PX points out that ISO Tariff Section 2.5.3.4 acknowledges this by requiring Generators, Loads, Metered Subsystem and UDCs to maintain voltage within specified power factor ranges at their points of interconnection with the ISO Controlled Grid. The ISO/PX consider these to be mandatory

319/ TANC at 77; SMUD at 29.

320/ ISO/PX June 23, 1997 Reply Comments at 179.

321/ Order No. 888-A, FERC Stats. & Regs. □31,048 at 30,228.

322/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,706.

obligations, for which no charges will be incurred by the ISO. The ISO/PX states that the ISO will contract for the provision of additional Voltage Support if this is needed. In such a case, the cost of procuring that support will be passed on to Scheduling Coordinators.

According to the ISO/PX, TANC's and SMUD's comments focus only on Voltage Support from a localized perspective, and do not give proper consideration to the ISO's responsibility to manage voltage profiles on the ISO Controlled Grid on a system-wide basis, to accommodate flow through transactions. At its meeting on June 17, 1997, the ISO Governing Board decided not to propose any change to the ISO Controlled Grid at this time. The ISO/PX points out that ISO Tariff Section 2.5.20.3 lists categories of Ancillary Service which can be self-provided and allows for future changes if it is considered appropriate.

September 2, 1997 Comments

DWR requests that the ISO Tariff be modified to allow for the combined provision of non-spinning and replacement reserves by several load resources within a Zone or Load group. 323/

DWR requests modification of the ISO Tariff to provide that generators unable to meet the minimum standards for VAR support may not lean on the ISO or other market participants. DWR notes that the ISO s amendments to Section 2.5.3.4 of the ISO Tariff would allow Generators to apply for an exemption from VAR standards. According to DWR, this provision does not comply with Order No. 888 principles of unbundling and self-provision of ancillary services. Thus, DWR contends that such Generators either pay for Ancillary Service requirements or provide them from another source. 324/

IEP and AES contend that ISO Tariff Section 2.5.3.4 allows the ISO to require generators entering the market as Participating Generators which are not also under interconnection agreements and are not Regulatory Must-Take or Reliability Must-Run, to produce or accept VARs without compensation. These parties oppose the requirement that new generators must provide voltage support, a valuable ancillary service, without any compensation. 325/ IEP states that Voltage Support clearly has a market value, as reflected in other language contained in ISO Tariff Section 2.5.3.4, and not providing payment is inconsistent

323/ DWR at 30.

324/ Id. at 31.

325/ AES at 2-5; IEP at 3-4.

with a competitive market for Ancillary Services. AES contends that this provision will discourage construction of new generation in constrained areas, because that is where voltage support is most likely to be needed, perpetuating constraints and inflating prices. Moreover, this requirement could distort the developing market for ancillary services, according to AES.

DWR requests clarification of Section 2.5.18 of the ISO Tariff regarding how often short-term Voltage Support will be called upon, and whether it would be used as a replacement for long-term Voltage Support. 326/ If short-term Voltage Support is to replace long-term Voltage Support, DWR requests amendment of the ISO Tariff to provide that the supplier of the long-term Voltage Support will be paid for costs incurred and more specificity on how Voltage Support will be provided on a long-term and short-term basis.

DWR also requests clarification of the ISO Tariff to specify that operation as a metered subsystem is only required for the literal self-provision of regulation (AGC). 327/

DWR notes that Section 2.5.6.2 requires electronic dispatch by the ISO through direct computer linkage. However, the system will not be available on January 1, 1998, thereby limiting which Generators or Loads can provide Ancillary Services, and also limiting self provision of Ancillary Services. DWR contends that such delays in implementing the ISO s electronic dispatch should be relieved by allowing dispatch via telephone or fax. 328/

BPA requests modification of ISO Tariff Section 2.5.20.5.2, to clarify that self-provision of ancillary services will be declared invalid only where an adjustment deviates from the original schedule and only to the extent that it places an additional burden on the ISO to provide ancillary services. 329/

Imperial objects to the revisions made to ISO Tariff Section 2.5.20.3 regarding the Metered Subsystem and System Unit concepts. Imperial recommends that the Commission direct the ISO

to amend ISO Tariff Section 2.5.20.3 to allow a Metered Subsystem

326/ DWR at 32.

327/ Id. at 33.

328/ Id.

329/ BPA at 20-21.

to Literally Self-Provide Ancillary Services in addition to Regulation through the use of a System Unit. 330/

CMUA contends that the ability to self-provide ancillary services using Metered Subsystems is critical to many Transmission Owners, who operate as an integrated System Unit, not on a Generator-by-Generator basis. CMUA contends that the August 15 filing improperly limits use of Metered Subsystems to Regulation. CMUA recommends that the Commission reject the proposed changes to ISO Tariff Section 2.5.20.3 and direct the ISO to revise the provision to allow a System Unit to provide ancillary Services for itself, the ISO, other Scheduling Coordinators, or the PX. 331/

Commission Response

Initially, Voltage Support and Black Start may not be self-provided under the ISO Tariff and will be procured by the ISO as the Control Area Operator. The ISO recognizes that as more experience is gained, the ISO may amend these restrictions in the future. 332/ We agree that Black Start must be provided based on the whole ISO Controlled Grid. The ISO must determine on a system-wide basis how best to isolate parts of its system for restoration following a System Emergency. Accordingly, we support the ISO Tariff provisions for initial operation.

The ISO interprets the TANC and SMUD Voltage Support concerns as adopting a localized perspective rather than the system-wide ISO Controlled Grid perspective (i.e., maintaining voltage within specified power factor ranges at their points of interconnection). This focus does not address the ISO's system-wide need for Voltage Support. For reliability reasons, we support the ISO's proposed initial requirement that system-wide Voltage Support should be provided by the ISO. Due to the circumstances of this restructuring proposal, we believe that the ISO is uniquely situated to have sole responsibility for supplying this service. After the ISO gains operational experience, this requirement should be reevaluated.

DWR's recommendation to combine Loads in the same Zone or Load group for purposes of submitting a single bid for Non-

Spinning and Replacement Reserves is unclear. If DWR is referring to the ability to submit ancillary service bids from a

330/ Imperial at 1-5.

331/ CMUA at 18-21. See also, Redding at 18-20.

332/ ISO/PX June 23, 1997 Reply Comments at 179.

system resource as part of a Metered Subsystem, we address those concerns above.

We agree with DWR that Participating Generators unable to meet the minimum standards for Voltage Support should not lean on the ISO or other Market Participants. In addition, we agree with DWR that Participating Generators unable to satisfy the ISO's standards must either pay for their ancillary service requirements or self-provide them from another source. However, we disagree with DWR's interpretation of Section 2.5.3.4 of the ISO Tariff that Participating Generators may apply for an exemption from the ISO's VAR standards and thereby not have to comply with or pay for VAR support. Section 2.5.3.4 of the ISO Tariff specifically provides that prior to the ISO granting an exemption the Participating Transmission Owner or UDC to whose system the generator is connected must notify the ISO of the existing contractual requirements for voltage support established prior to the ISO's Operations Date for that generator. Section 2.5.3.4 of the ISO Tariff further provides that the ISO cannot grant an exemption from such existing contractual requirements.

We reject DWR's request for clarification regarding Section 2.5.18 of the ISO Tariff. DWR requests that the ISO clarify that short-term voltage support will be procured only when voltage support procured on an annual basis is insufficient. As explained above, Section 2.5.3.4 clearly provides that the ISO will not call upon Generating Units to operate outside of their mandatory power factor range (short-term voltage support) unless no other economic sources are available. In addition, we find that it is inappropriate to require the ISO to specify how often short-term voltage support will be procured. The ISO cannot reasonably predict when it will need to procure additional incremental voltage support. With regard to DWR's recommendation that ISO Tariff Section 2.5.18 provide that suppliers of long-term voltage support will still be compensated if the ISO relies on short-term voltage support service, we find that such provisions are appropriately addressed in the contract between the long-term voltage support service provider and the ISO.

We find DWR's recommended change to Section 2.5.20.3 of the ISO Tariff to be confusing. Section 2.5.20.3 provides that a Metered Subsystem can only self-provide Regulation service, not, as DWR states, that an entity has to be a Metered Subsystem in order to self-provide Regulation service. We discuss the merits of the ISO's proposal above.

DWR notes that Sections 2.5.6.2 and 2.5.20.7 of the ISO Tariff requires that Generators and Loads that supply Ancillary Services must be dispatched electronically by the ISO through a direct computer link. DWR further states that the system that will control electronic dispatch will not be available on January 1, 1998. DWR states that this will severely limit the number of

Generators and Loads that can provide the ISO or self-provide Ancillary Services. DWR requests that for an interim period until electronic dispatch is fully available, the ISO should waive this requirement and permit ancillary service resources to be dispatched via telephone call or fax. Consistent with our earlier determinations, we require the ISO to notify the Commission in its Staging Plan reports of the status of its electronic dispatch capability. To the extent the ISO will be unable to perform this function as of the start of ISO operations, we direct the ISO to permit the dispatch of all ancillary service resources by telephone or fax. We find that this is within the boundaries of the ISO's discretion under Section 2.5.6.2 of the ISO Tariff. The ISO should notify the Commission when it is able to begin electronic dispatch of all ancillary service resources.

We disagree with AES Pacific and IEP that Section 2.5.3.4 of the ISO Tariff inappropriately provides that Generating Units provide VAR support without compensation. Section 2.5.3.4 of the ISO Tariff provides that Generating Units maintain a minimum power factor range within a band of 0.90 lagging and 0.95 leading and that generators will receive no compensation for operating within these specified ranges. We find that this is a necessary and critical requirement for all generators connected to the ISO Controlled Grid. Without such a requirement, the ISO will be unable to fulfill its responsibilities as Control Area Operator to maintain system stability. This provision merely specifies a broad power factor range requirement. To the extent a generator cannot meet the operating power factor requirement, the generator can apply to the ISO for an exemption from this requirement. With regard to AES Pacific's and IEP's contention that the ISO should competitively procure Voltage Support, we note that Section 2.5.3.4 clearly provides that if the ISO requires additional Voltage Support, it will procure such services competitively through negotiated contracts from any available source which meets the ISO's technical requirements on an annual or other such basis. Moreover, Section 2.5.3.4 of the ISO Tariff provides that if no more economic sources are available the ISO may instruct a Generating Unit to move its MVar output outside its mandatory range. In that case, if the Generating Unit must reduce its MW output it will be compensated by the ISO.

We reject BPA's recommended clarification to Section 2.5.20.5.2 of the ISO Tariff to declare invalid self-provision of ancillary services only where an adjustment deviates from the original schedule and places an additional burden on the ISO. We find that the ISO's proposed language is sufficiently clear and achieves BPA's objective.

With regard to various parties' objections to the revised

Section 2.5.20.3 of the ISO Tariff, we note, as explained above, that the ISO intends to revise the ISO Tariff after January 1,

1998 to clarify the role, responsibility and requirements associated with an Metered Subsystem. The Commission considers this to be an extremely important issue and urges the ISO to act expeditiously to resolve all parties' concerns.

D. Access Charge

As described in our earlier orders, the ISO's proposed Access Charge would provide all transmission customers access to the entire ISO Controlled Grid at non-pancaked rates. 333/ The proposed transmission Access Charge would be applied to transmission customers that withdraw power from the ISO Controlled Grid. The Access Charge is designed to recover the transmission revenue requirement associated with the facilities that the Participating Transmission Owners transfer to the ISO. As proposed, the transmission Access Charge would be a rolled-in rate determined for each historical service area. To implement this proposal, each Participating Transmission Owner in the ISO would establish an Access Charge, approved by the appropriate regulatory authority, that would apply to the customers located in its service territory. 334/ Thus, the Access Charge for a particular transaction would be based on the area of the ISO Controlled Grid from which the customer withdraws power from the grid.

Entities wheeling power through or out of the ISO Controlled Grid would pay the transmission Access Charge of the Transmission Owner located where the power leaves the ISO Controlled Grid. The ISO Tariff provides that where two or more Participating Transmission Owners own the facilities at the exit point, the charge will be the weighted average Access Charge of all Transmission Owners of the exit point. Such wheeling revenues would be treated as revenue credits to the Participating Transmission Owners that are paid the Access Charge.

Each Transmission Owner would bill and collect the Access Charge from the retail customers in its respective service area. The ISO would be responsible for collecting the wheeling service Access Charges from wheeling parties.

333/ See e.g., November 26 Order, 77 FERC at 61,799 and July 30, Order, 80 FERC at 61,428 (footnote 41).

334/ PG&E, SoCal Edison, and SDG&E separately filed in Docket Nos. ER97-2 000, ER97-2355-000, and ER97-2364-000, respectively, to establish th revenue requirement for their individual Access Charges.

California Restructuring Legislation

As we explained in the November 26 Order, the Restructuring Legislation outlines a process whereby the ISO staff and Governing Board have a two-year period to study the original access charge methodology and to evaluate alternatives based on certain principles including an equitable balance of costs and benefits. The Restructuring Legislation outlines three possible procedural outcomes for determining the ISO s Access Charge. First, if the ISO Governing Board reaches a consensus on a proposed rate methodology, it will then submit its recommendation to the Commission. The ISO Governing Board is free to select any Access Charge rate methodology advocated in these proceedings (e.g., a utility-specific, regional-local, or state-wide ISO rate methodology).

Second, if the ISO Governing Board fails to reach a consensus decision on the rate methodology, the rate methodology will be determined through the ISO's ADR Procedures. If the ADR Procedures are successful, the rate methodology will be filed with the Commission. Finally, if these procedures are unsuccessful, the Restructuring Legislation provides that the ISO will recommend to the Commission a two-part default rate methodology consisting of (1) a uniform regional transmission Access Charge; and (2) a utility-specific local transmission Access Charge. 335/

Regardless of the procedural process, the ISO-recommended rate methodology is to be filed with the Commission at least sixty days before the end of the two-year period. If the ISO Governing Board-recommended or the ADR-recommended rate methodology is accepted, the rates are proposed to go into effect when the two-year period ends. The default rate methodology is proposed to become effective on the later of the end of the two-year period or the termination of the stranded cost recovery period.

Self-Sufficiency Test

The ISO Tariff proposes to apply a "Self-Sufficiency test" to all Participating Transmission Owners. The ISO Tariff defines a "Self-Sufficient" Participating Transmission Owner as one for which the sum of the Dependable Generation within its service area (regardless of ownership) and the firm import

335/ Section 9600(a)(2)(C) of the Restructuring Legislation defines regiona facilities as transmission facilities operating at or above 230 kV p an appropriate percentage of lower voltage transmission facilities.

interconnection (including transmission rights) to the Participating Transmission Owner's service area is greater than or equal to the monthly peak load for the Participating Transmission Owner's service area plus minimum WSCC operating reserves. See ISO Tariff, Sections 7.1.2 and 7.1.3. Conversely, Dependent Participating Transmission Owners are those entities whose sum of generation and transmission import capability is less than its monthly peak load. Dependent Participating Transmission Owners would be charged a transmission access fee which would include a portion of the Access Charge of the Participating Transmission Owner they depend on. Specifically, a Dependent Participating Transmission Owner will pay a Participating Transmission Owner an Access Charge equal to the product of the amount in MW that the Dependent Participating Transmission Owner is deficient (Non Self-Sufficient Contract Demand) and the Non Self-Sufficient Contract Demand Rate of the Participating Transmission Owner, which is equal to that Participating Transmission Owners' base transmission revenue requirement divided by the sum of the highest peak in each month. 336/

Transmission Revenue Balancing Account

The ISO proposes to that each Transmission Owner establish a Transmission Revenue Balancing Account (TRBA). ISO Tariff Original Sheet No. 347 defines the TRBA as, "A mechanism to be established by each Participating TO [Transmission Owner] which will ensure that all Transmission Revenue Credits flow through to its transmission customers." The merits of each Participating Transmission Owners' TRBA proposal will be addressed in their respective rate cases. 337/

In our November 26 Order , we required the ISO to clarify how the proposed TRBA would work in conjunction with the tracking account established under California's Restructuring Legislation. Specifically, we stated that the Phase II filing must clarify whether the ISO continues to propose to utilize balancing accounts in conjunction with the Tracking Account mechanism, and, if so, how these two mechanisms would operate together and the proposed duration of the balancing account. The Commission also stated that it was unclear how and for what duration refunds or surcharges under these accounts would be imposed and whether the

336/ See ISO Tariff Section 7.1.3.

337/ See TO Tariff Section 5.5, pp. 23-24.

proposed tracking mechanisms would result in retroactive

ratemaking. 338/

The March 31, 1997, Joint Response of the Companies clarified that the Tracking Account provided for under the Restructuring Legislation serves a completely different purpose from that of the TRBA. The Companies explain that the purpose of the Tracking Account is to prospectively collect the difference between the initial Access Charge and the Access Charge rate established under any new Access Charge methodology. The Companies state that by providing for the prospective (i.e., after the initial two-year period the initial Access Charge is to be effective) collection of any differences between the Access Charges, the Companies ability to recover stranded costs will not be affected. 339/ Therefore, the Companies state that the Tracking Account clearly will not result in retroactive ratemaking.

Contested Issues as Identified by the ISO/PX

SoCal Gas opposes the one-part Access Charge proposed by the ISO. SoCal Gas proposes a two-part Access Charge for the two distinct services SoCal Gas believes are provided by the ISO: (1) local transmission; and (2) regional transmission. SoCal Gas' proposal would allocate the embedded cost of transmission above 230kV to the non-California Generators through the regional transmission Access Charge and the remaining transmission (230kV and below) costs to consumers through a local transmission Access Charge.

PG&E, TANC, Modesto, and others contend that the Self-Sufficiency test is not appropriate. A number of parties object to the Self-Sufficiency test on the grounds that the proposal was

338/ November 26 Order at 61,828.

339/ The Restructuring Legislation established a rate freeze for all reta customers, under which the Companies are at risk for any stranded co they cannot recover within the rate ceiling under the rate freeze. is, the Companies must recover their stranded costs from the differe in revenues between their frozen retail rate level and their opera costs until March 31, 2002 or when all stranded costs have been recovered. Therefore, if the Access Charge increases, the resulting increase will bring the Companies closer to the rate freeze ceiling established under Restructuring Legislation. See Companies' Joint Response to Commission Questions in Phase I Orders filed March 31, 1 at pp. 9-13.

not agreed to by the WEPEX Steering Committee. 340/ Parties argue that the Steering Committee decision provided that the Self-Sufficiency test should not be applied during the first two years of ISO operations, and during that interim period all Transmission Owners should be presumed Self-Sufficient. 341/

In addition, parties claim that the definition of Firm Import Interconnection Transmission Capacity is too narrow because it includes only that transmission import capacity which is directly connected with a Transmission Owner's system and therefore excludes certain transmission assets in which very substantial investment has been made. Parties also claim that the definition of Dependable Generation does not give full credit for generating capacity which is available to provide Spinning Reserve at the time of the annual peak Load and discriminates against generating plant which is less than 3 years old. 342/

PG&E, on the other hand, claims that the Self-Sufficiency test needs to made more rigorous. 343/ PG&E recommends that the Self-Sufficiency test be based on the Monthly Peak Load of the Transmission Owner in order to meet demand and operating reserve requirements. 344/

The California Commission contends that the Commission should now rule that the successor Access Charge methodology must be based on certain cost causation principles, i.e., reflecting time-differentiated demands and distance factors, and avoiding vertical pancaking. 345/

Alternatively, San Francisco argues that the ISO Tariff should not include a discussion of the successor Access Charge in Section 7.1.6 because the discussion presumes to provide for a rate design and the ISO should not be permitted to submit a proposal for Commission approval at this time. 346/ San

340/ PG&E at 3; TANC at 56; and Modesto at 31.

341/ TANC at 55; Modesto at 31.

342/ See; e.g., DWR June 6, 1997, Comments at 20; SMUD September 2, 1997, Comments at 19.

343/ PG&E at 3.

344/ PG&E at 3 and 5.

345/ California Commission at 66.

346/ San Francisco at 22.

Francisco states that the ISO Tariff should contain only currently applicable terms and conditions. 347/

PacifiCorp contends that the failure to allow discounting of transmission rates is discriminatory and will eliminate the existing Pacific Northwest-Southwest economy energy trading market. Specifically, PacifiCorp states that Section 7.1.4.1 of the ISO Tariff provides that the price of exports from California will be based on a fully allocated rate and does not allow

discounting for such transactions. PacifiCorp claims that economy energy transactions now take place through California between the Pacific Northwest and the desert Southwest regions of the WSCC using non-firm transmission over congested lines and that the price of California transmission has been discounted in order to maximize the volume of service and revenues. 348/ PacifiCorp asserts that without discounting, the ISO Tariff will eliminate the Pacific Northwest-Southwest economy Energy trading that now exists, and it will have the anticompetitive effect of "trapping" Southwest generation in California.

A number of parties raise concerns over the rates, terms, and conditions of service over the Companies' proposed Wholesale Distribution Access Service Tariffs. In addition, parties raise concerns over the discriminatory treatment of wholesale customers who have to take service under both the ISO Tariff and the Companies' Wholesale Distribution Access Tariffs. 349/

June 23, 1997 ISO/PX Reply Comments

The ISO/PX state that SoCal Gas' two-part access fee proposal should be rejected as discriminatory. 350/ The ISO/PX argue that SoCal Gas' proposal would allocate the embedded cost of transmission only to remote generation, a large percentage of which is coal fired, and none of the embedded cost of transmission to in-state generation, a correspondingly large percentage of which is natural gas fueled. The ISO/PX argue that such a cost allocation is arbitrary. In addition, the ISO/PX contend that SoCal Gas' argument that such discrimination is necessary as a means to provide a signal for efficient siting of new generation is flawed. The ISO/PX state that their proposal,

347/ San Francisco at 23.

348/ PacifiCorp at 10.

349/ See, e.g., June 6, 1997, Comments of Vernon at 4; September 2, 1997, Comments of EPUC at 15-16.

350/ ISO/PX June 23, 1997, Reply Comments at 224-226.

based on the short-run marginal cost of transmission, is superior to SoCal Gas' arbitrary cost-allocation proposal.

The ISO/PX also reject SoCal Gas' contention that allocating transmission costs to Generators will result in savings to consumers on the delivered cost of power. The ISO/PX state SoCal Gas' proposal will redistribute costs to Generators and artificially increase the price of out-of-state generation and may create additional stranded cost of Generation by adding fixed transmission costs to fixed Generation costs.

The ISO/PX state that the determination of the Self-Sufficiency test is a matter to be resolved between those parties

intending to become Participating Transmission Owners and is not an appropriate matter for the ISO to address. The ISO/PX state that the ISO Governing Board at its meeting on June 17 expressed a willingness for the ISO to facilitate discussions to help achieve an informal settlement of these issues, but that if the parties are unable to reach agreement, the Commission will have to rule on this issue. 351/

In response to the California Commission's recommendation that the Commission require that the successor Access Charge rate methodology be based on certain cost causation principles, the ISO/PX state that the Commission should not prescribe or preclude any particular pricing methodology for the successor Access Charge, but should be receptive to new pricing proposals that the ISO may consider and submit to the Commission in the future. 352/

With regard to PacifiCorp's concerns over discounting, the ISO/PX state that the ISO's proposed non-pancaked transmission rates for access to the entire ISO Controlled Grid may be comparable to present discounted rates. The ISO/PX also state that discounting would invite gaming of the ISO's rules and would introduce inefficiency in the market. The ISO/PX state that discounting is not planned at this time, but that the ISO may consider providing discounted transmission service in the future. 353/

Finally, with regard to parties concerns over the Companies' proposed Wholesale Distribution Transmission Tariffs, the ISO/PX

351/ ISO/PX June 23. 1997, Reply Comments at 220-222.

352/ ISO/PX June 23, 1997, Reply Comments at 222-223.

353/ ISO/PX June 23, 1997, Reply Comments at 236.

state that the parties raise complex issues which the ISO/PX intend to address in the appropriate proceedings. 354/

September 2, 1997 Comments

CMUA requests clarification that the ISO Tariff contemplates no Commission review of the Access Charge of non- public utility Participating Transmission Owners, either directly or indirectly through ADR procedures. Also, CMUA recommends modification of the Transmission Owner Tariff to reflect the distinction between public utilities and non-public utility Participating Transmission Owners. 355/

Several parties argue that the ISO s current (Self Sufficiency Test) rate methodology, in conjunction with PG&E s proposal, would offer publicly-owned utilities virtually no

compensation for the significant transmission facilities they would contribute to the ISO. For example, NCPA points out that because the California-Oregon Transmission Project (COTP) is a backbone facility not directly connected to any load, its owners would not be compensated for its contribution. 356/

DWR requests that the Commission clarify that the initial ISO pricing methodology will be afforded no precedential effect. DWR states that the ISO does not object to its position. Moreover, DWR contends that transmission pricing after the initial period should be consistent among the ISO Tariff and the Utility specific tariffs for transmission, sub-transmission, and distribution facilities which the Participating Transmission Owners continue to control. DWR is concerned that the successor rates under these tariffs ensure consistency to ensure restructuring goals are not undermined.

DWR accepts the ISO s access fee proposals on an interim basis and is willing to defer consideration of off-peak rates until after January 1, 1998, as stated in Appendix 1 of the August 15 Filing. However, DWR supports the use of off-peak rates if the Commission at the outset requires transmission pricing more reflective of cost causation.

CMUA argues that the self-sufficiency test excludes credit for certain existing and future facilities because it applies a contract path to a network environment. According to CMUA,

354/ ISO/PX June 23, 1997, Reply Comments at 54.

355/ CMUA at 12.

356/ NCPA at 13; M-S-R at 7-9; Santa Clara and Palo Alto at 6; Redding at Southern Cities/Azusa and Banning at 9.

Transmission Owners with entitlement to facilities not connected to their city gates will receive no credit for their ownership of and prior investments in capacity that benefits the entire network, and they will lose valuable scheduling rights. CMUA also argues that the contract path methodology fails to reflect the fact that many contracts provide access to a Scheduling Point (rather than a specified contract point, as specified in the definition of Firm Import Interconnection Transmission Capacity), where contract entitlement holders transact business with generators. Moreover, CMUA contends that the contract path methodology underlying the self-sufficiency test is unworkable when applied to entities such as power marketers that do not have traditional service territories. 357/

CMUA also contends that the definitions of Firm Import Interconnection Transmission Capacity and Dependable Generation, in combination, lead to double counting. CMUA notes that generation sources located out of the service areas of municipal Transmission Owners will count towards the Access Charge responsibilities of the Companies under the definition of Dependable Generation, but will also count toward the CMUA

members Self-Sufficiency determination under the definition of Firm Import Interconnection Transmission Capacity. 358/

Until a California-wide, rolled-in rate for transmission facilities is in place, NCPA proposes that the Self-Sufficiency test under ISO Tariff Section 7.1.3 be modified to be based on revenue requirement rather than on contract demand. 359/ Thus, NCPA recommends that ISO Tariff Section 7.1.3 provide: 360/

> A Dependent Participating Transmission Owner shall pay to the Participating Transmission Owner to which it is physically interconnected, an Access Charge equal to (1) the product of the Access Charge rate of that Participating Transmission Owner and the Contract Demand of that Dependent Participating Transmission Owner; minus (ii) the revenue requirement associated with transmission facilities contributed to the ISO grid by or on behalf of that Dependent Participating Transmission Owner; plus (iii) the TRBA adjustment charges as provided in section 5.5. of the Transmission Owner Tariff. [The remainder of ISO Tariff Section 7.1.3 could then be deleted.]

357/ CMUA at 12-18; NCPA at 15-17.

358/ CMUA at 12-18; Southern Cities/Azusa and Banning at 111-12.

359/ See also Palo Alto at 8.

360/ NCPA at 20.

DWR requests clarification and modification of the Self-Sufficiency test to provide that it be based on a methodology and time period consistent with the Access Charge methodology. According to DWR, this would avoid over-collections of Access Charges. In addition, DWR points out that its off-peak pricing proposal would alleviate the Companies expressed concerns that off-peak users would not pay for transmission service.

CCEM argues that the ISO Tariff Section 7.1.4.1 prohibits discounts by establishing a Wheeling Access Charge, rather than a Wheeling Access price cap. 361/ ECI recommends that the ISO Tariff be amended to contain the Order No. 888 requirements relating to discounts for transmission service. 362/ According to ECI, the Tariff should reflect the following Commission guidelines: (1) offers of discounts must be posted on the OASIS; (2) customer-initiated requests for discounts must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS, and similarly situated transmission customers must be offered the same discounted transmission service rate. 363/

Commission Response

In our November 26 order we stated that our preliminary

review indicated that the ISO's transmission Access Charge rate proposal appeared to be a reasonable method of recovering the transmission revenue requirements of Participating Transmission Owners. We reaffirm that finding here. While we have certain concerns with regard to the ISO's proposal, as discussed below, we find that the proposal minimizes cost-shifting during the transition period and is reasonable.

An integral component of the ISO's transmission pricing proposal is the Self-Sufficiency test. In our November 26 order we stated that:

> The Phase II filing should provide greater detail regarding the calculation and ratemaking effect of this test. Specifically, the Phase II filing must include an explanation of how charges collected from an entity will be credited back to the Transmission Owner whose system the customer utilizes. The Phase II filing should also clearly define dependable generation and firm import capability, and should explain why these

361/ CCEM at 15.

362/ See Pro Forma Tariff, Schedule 7.

363/ ECI at 13.

> criteria are necessarily accurate indicators that a utility is not dependent upon the transmission system of another transmission-owning utility.

The Phase II filing satisfied this requirement. The Self-Sufficiency test appears to minimize cost-shifting as a result of implementing the ISO structure; customers will continue to pay the cost of transmission on their local Transmission Owner's system. However, we are sympathetic to the concerns raised by CMUA, TANC, NCPA and others that the ISO's proposal fails to account for and reflect the integrated nature of certain of their transmission facilities. These are factual issues that are appropriately addressed in the Companies' individual Transmission Owner Tariff rate cases. As we stated in Order No. 888, cost credits related to customer-owned facilities are appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts. 364/ In this instance, the issue would be whether a Participating Transmission Owner's transmission facilities located in the service territory of another Participating Transmission Owner warrant a customer-specific revenue credit. We reiterate that in order for a Transmission Owner's transmission facilities to warrant a credit, it must be demonstrated that the facilities are integrated with the transmission system of the local Transmission Owner. As we stated in Order No. 888, where disputes arise over the treatment of certain transmission facilities, we encourage all parties to pursue resolution through the Transmission Owner Tariff s ADR Procedure 365/ rather than seek resolution at the Commission. 366/

We agree with DWR that Section 7.1.3 of the ISO Tariff should be modified to state that to the extent a Transmission Owner has existing transmission service contracts for the delivery of their power requirements, that Transmission Owner has satisfied the Self-Sufficiency test until such time as those contracts have been terminated. Consistent with that position, all Transmission Owners will continue to pay the cost of their own transmission facilities and the transmission costs under any existing transmission service agreements.

We also have concerns with regard to the applicability of the Self-Sufficiency test under any new ratemaking methodology adopted pursuant to Section 7.1.6 of the ISO Tariff. We caution the ISO that we will revisit this issue when the ISO files a new,

364/ Order No. 888, FERC Stats. and Regs. □ 31,036 at 31,742.

365/ We note that the ADR procedure referenced in the Transmission Owner Tariffs formally adopts the ISO Tariff ADR Procedure.

366/ Order No. 888, FERC Stats. and Regs. □ 31,036 at 31,743.

or successor, rate methodology pursuant to Section 7.1.6. We also advise the parties to this proceeding that the Commission anticipates that the new ratemaking methodology adopted by the ISO Governing Board must continue to accurately and fairly reflect the contributions to the ISO's integrated transmission system of all Transmission Owners. We note that the alternative rate methodology outlined in the Restructuring Legislation and referenced in Section 7.1.6 of the ISO Tariff may remedy some of the concerns raised by the SoCal Gas, CMUA, and others. We decline at this time to prescribe or make recommendations on the proper design of the successor rate methodology and therefore will not adopt the California Commission s recommendations.

Discrimination

In our November 26 Order the Commission raised concerns regarding SoCal Edison's decision to exclude from the ISO Controlled Grid certain facilities which may be used to serve certain wholesale customers in the future. We stated that wholesale customers located within SoCal Edison's and PG&E's service territory may have to obtain service under two separate Commission-jurisdictional tariffs and that to the extent other ISO transmission customers have access to the transmission system under a single tariff, SoCal Edison's and PG&E's customers may raise legitimate concerns regarding discriminatory treatment. 367/

A number of parties raised concerns over the Companies' proposed Wholesale Distribution Access Tariffs. We decline in this order to address the rates, terms, and conditions of service under the Companies' distribution tariffs. Issues addressing the reasonableness of the Companies' tariffs are best addressed in

their individual rate dockets. In addition, parties will be free to raise any concerns regarding discriminatory treatment in the Companies' individual rate proceedings.

Discounting

We reject PacifiCorp's recommendation that the ISO Tariff be amended to initially provide for the discounting of transmission service rates for exports. The Commission has never required that transmission providers offer discounted transmission rates for a particular service. Moreover, while the ISO may elect to submit a discounting proposal in the future, we will not require the ISO to do so at this time in light of the pressures and time constraints of implementing the ISO. Any future discounting proposal will require balancing the interests of Transmission

367/ November 26 Order, 77 FERC at 61,827.

Owners, who may face a reduced contribution to their fixed transmission costs, and Generators, who may benefit from discounted transmission rates. However, the discretion as to whether to discount a transmission rate, and the extent of that discount, is ultimately up to the Transmission Owner whose facilities will be utilized. Any such future discounting proposal must be made in the context of a Participating Transmission Owner s rate proposal because the ISO is responsible for only collecting the revenue requirement. (As noted above, each Transmission Owner is responsible for collecting the Access Charge from the retail customers in its service territory. The ISO will bill and collect, but not establish the Access Charge for wheeling customers).

PacifiCorp argues that low-cost generators in the Southwest will be "trapped" in California absent discounts. We note that under the ISO's proposal all Generators will have access to the entire ISO Controlled Grid by paying a single (i.e., non-pancaked) Access Charge. We are not now convinced that the ISO s regional transmission pricing proposal as compared to the historically discounted but pancaked rates of the individual Companies will trap generation as PacifiCorp suggests. We direct the ISO to address the discounting issue in its future transmission rights proposal and the alternative rate methodology proposal provided for Section 7.1.6 of the ISO Tariff.

E. ISO Scheduling Practices and Procedures

Scheduling Coordinators

In order to facilitate and expedite the day-ahead and hour-ahead scheduling procedures on the ISO Controlled Grid, the ISO proposes to establish an intermediate entity called a Scheduling Coordinator. Scheduling Coordinators are the only entities that can submit schedules to the ISO. The PX will be a Scheduling Coordinator. Scheduling Coordinators will have to operate on a

24-hour basis, and will submit to the ISO schedules for all parties they represent. Subject to the certification criteria for Scheduling Coordinators contained in the ISO Tariff, 368/ any customer may be its own Scheduling Coordinator. At the direction of the ISO, Scheduling Coordinators will be responsible for coordinating and allocating reductions in load as well as altering generation schedules. Similarly, Scheduling Coordinators will allocate billings among their aggregated loads and make payments to designated generators and will schedule deliveries to or from other Scheduling Coordinators. Scheduling Coordinators will also be responsible for tracking and settling all intermediate trades, such as those with power marketers. In addition, the ISO proposes that it will handle settlement with and billing of Scheduling

368/ See Section 2.2.3 and 2.2.4 of the ISO Tariff.

Coordinators for ancillary services, energy imbalances caused by scheduling deviations, transmission congestion, and administrative costs. Schedules submitted to the ISO will be the basis for the settlement process with Scheduling Coordinators.

The November 26, 1996, Phase I order accepted, on an interim basis, the ISO's proposal to establish rules for Scheduling Coordinators. The Commission also stated that the Phase II filing must include a detailed description of the technical and financial requirements to qualify as a Scheduling Coordinator. In particular, the November 26 Order stated that the Phase II filing was to provide more detail on all the operational roles that the Scheduling Coordinators will perform and their interaction with the ISO. 369/

The Phase II Filing

The ISO/PX have proposed detailed requirements for becoming and operating as a Scheduling Coordinator. 370/ In addition, the ISO/PX have submitted a pro forma Scheduling Coordinator Agreement that all potential Scheduling Coordinators will have to execute with the ISO.

Contested Issues Identified by the ISO/PX

Turlock contends that Scheduling Coordinators should be relieved of the obligation to provide notice to the ISO of changes in the Eligible Customers they represent. 371/

EPUC/CAC contend that the obligation of Scheduling Coordinators (under Section 2.2.6.8 of the ISO Tariff) to provide the ISO rolling 12-month Demand Forecasts should be amended to cover only the week ahead. EPUC/CAC suggest that annual Demand Forecasts will be of limited use because switching of Market Participants between Scheduling Coordinators will make the data highly volatile. 372/

Southern Cities/Azusa and Banning contend that the ISO should be responsible for the collection of Scheduling Coordinator's debts and that this should be included as a general

369/ November 26 Order, 77 FERC at 61,836.

370/ See, e.g., ISO Tariff Sections 2.2.3; 2.2.4; 2.2.5; and 2.2.6.

371/ Turlock at 40.

372/ EPUC/CAC at 11.

obligation on the ISO under ISO Tariff Section 2.2.1. 373/ Southern Cities/Azusa and Banning argue that if Scheduling Coordinators are made responsible for the collection of bad debts, the transaction costs may prove prohibitive for individual Scheduling Coordinators. 374/

CCEM contends that all Scheduling Coordinators, not just those who can meet the criteria for a Metered Sub-System, should be able to use system resources to make adjustment bids and offer ancillary services. 375/

June 23, 1997 ISO/PX Reply Comments

In response to Turlock's recommendation that Scheduling Coordinators be relieved of the requirement to periodically notify the ISO of changes in the Eligible Customers they represent, the ISO states that this notification provision is essential in order to enable the ISO to know which Scheduling Coordinator is responsible for any Imbalance Energy attributable to the Eligible Customer's meter. 376/ The ISO/PX states that Turlock's main objection is that it questions whether the ISO would ever make use of this information. The ISO/PX objects to any change because without this requirement, the ISO's ability to discharge its duties under the Tariff would be adversely affected.

With regard to EPUC/CAC's objection to the provision of annual Demand Forecasts, the ISO/PX maintains that annual forecasts are likely to be of considerable benefit to the ISO for planning purposes. Therefore, the ISO/PX states that it would be inappropriate to limit the obligation of Scheduling Coordinators to publish only weekly forecasts. In addition, the ISO/PX states that requiring each Scheduling Coordinator to produce its forecast on the basis of firm contractual commitments will avoid excessive volatility.

In response to Southern Cities/Azusa and Banning's recommendation that the ISO be responsible for collecting bad debts, the ISO/PX maintains that it is unusual for the administrator of a market to take responsibility for pursuing the debts of traders. The traders who take the benefits of trading should also take the payment and bad debt risks.

373/ cite to be provided.

374/ Southern Cities/Azusa and Banning at 9.

375/ CCEM July 23, 1997 filing at 2.

376/ See Section 2.2.5 of the ISO Tariff.

September 2, 1997 Comments

Numerous parties oppose the August 15 proposal to prohibit inter-Scheduling Coordinator trades between congestion zones, regardless of the existence of congestion, under Sections 2.2.6.4 and 2.2.11.3.3 of the ISO Tariff. 377/ BPA argues that this prohibition also precludes trades including energy generated outside of California.

BPA and ECI request that the Commission direct the ISO to amend section 2.1 of the ISO Tariff to expressly permit multiple Scheduling Coordinators to trade at each Tie Point Meter and to direct the ISO and PX to amend their software to make trading by multiple Scheduling Coordinators possible at Tie Point Meters by January 1, 1998. 378/ CMUA requests that the Commission order the PX to correct the one Scheduling Coordinator per meter requirement by July 1, 1998. 379/ BPA states that if more than one Scheduling Coordinator wants to use a Tie Point Meter then it must coordinate with other Scheduling Coordinators to develop rules for making such allocations and to notify the ISO. This effectively requires all Scheduling Coordinators at a single Point to designate a single Scheduling Coordinator, which would be a competitor, to receive highly sensitive customer and pricing information. Alternatively, the Scheduling Coordinators would have to hire a new Scheduling Coordinator at considerable expense, driving up the price of power at that Point. BPA argues that the ISO has not demonstrated its inability to develop software by January 1, 1998 to accommodate multiple Scheduling Coordinators trading through shared tie points or points of injection. EPUC/CAC continue to oppose the limitation to using one Scheduling Coordinator.

BPA objects to section 2.5.20.1 of the ISO Tariff, insofar as it does not permit a Scheduling Coordinator, consistent with WSCC Minimum Operating Reliability Criteria (MORC), to subtract from its operating reserve obligation the operating reserves provided by firm power imported from outside of the ISO control area. Thus, for power imported from outside of the ISO grid, the Scheduling Coordinator must pay twice for operating reserves. In contrast, ISO Tariff Section 2.5.3.2, provides that the ISO will subtract system firm capacity purchased outside of the ISO control area. According to BPA, this disparate treatment unfairly burdens and discriminates against power imported from outside the ISO control area. BPA recommends modification of

377/ E.g., EPUC/CAC at 16-17, ECI at 7-8, CCEM at 11.

378/ ECI at 8-10.

379/ CMUA at 31-33.

Sections 2.5.20.1 and 2.5.28 of the ISO Tariff to permit reduction of the operating reserve share owed by a Scheduling Coordinator by the amount of system firm capacity purchased from outside the ISO control area.

PG&E points out that "the systems being developed will not support" the requirement to maintain an operating reserve equal to the total amount of interruptible imports scheduled by a Scheduling Coordinator for a given hour, under ISO Tariff Section 2.5.3.2. Accordingly, PG&E recommends that the provision be revised to reflect that initially a procedural "work-around" shall be established until the systems can do it automatically. PG&E states that this language is necessary to ensure that the ISO will not charge all Scheduling Coordinators for the ancillary service requirements of a Scheduling Coordinator importing interruptible energy. 380/

Also, with respect to this section, BPA notes that the WSCC has additional minimum operating criteria that the ISO has not referenced in its Tariff. Therefore, states BPA, it is unclear whether the ISO intends to comply with them. BPA recommends revision of the Tariff to explicitly state that the ISO will satisfy all WSCC criteria. 381/

IEP requests that the list of information provided by Scheduling Coordinators that must be treated as confidential should be supplemented to include: (a) Information submitted by a Scheduling Coordinator under ISO Tariff sections 2.2.3.1 and 2.2.3.3, such as documents demonstrating Scheduling Coordinator capabilities, customer lists, etc.; (b) Information, letters of credit, etc. submitted by Scheduling Coordinator under ISO Tariff section 2.2.3.2; and information submitted to the ISO in the course of the Application process under ISO Tariff Section 2.2.4.2. 382/

EPUC/CAC state that ISO Tariff Section 2.2.7.3 has not been adequately modified to respond to its concerns regarding excessive security requirements for Scheduling Coordinators. According to EPUC/CAC, the calculation of potential outstanding liability remains onerous and will continue to be a market barrier. EPUC/CAC recommend that the amount be limited to the rolling average daily imbalance times the number of days for which the Scheduling Coordinator's settlements are typically not yet available. (EPUC recommends that initially an arbitrary

380/ PG&E at 11.

381/ BPA at 16.

382/ IEP at 7.

percentage would be needed, but that it should be much lower than expected gross daily energy scheduled.) 383/

September 16, 1997 Comments

In response to the overwhelming opposition to the ISO/PX proposal to restrict Inter-Scheduling Coordinator trading between zones, the ISO/PX propose modifications to the ISO and PX tariffs, as well as the Master Definitions Supplement. 384/

The PX proposes the following modification to PX Tariff Section 3.4.7.3:

> Each Inter-Scheduling Coordinator Trade shall be treated as an export schedule in the Balanced Schedule of the selling trader and as an import in the Balanced Schedule of the purchasing trader. The Scheduling Coordinators which are parties to the Inter-Scheduling Coordinator Trades shall specify a single Zone in which the Energy transaction is deemed to take place.

The ISO proposes the following modification to ISO Tariff Section 2.2.6.4:

> Billing and settling an Inter-Scheduling Coordinator Trade shall be undertaken in accordance with the agreement between the Scheduling Coordinators who are parties to that trade, provided that they shall specify a single Zone within which the trade is deemed to take place.

In addition, the ISO and PX propose to amend the definition of Inter-Scheduling Coordinator Trades in the Master Definitions Supplement to read, "Energy transactions between Scheduling Coordinators which are permitted under the ISO Tariff to take place."

Commission Response

With regard to Turlock's objection to the requirement that Scheduling Coordinators provide notification of change in Eligible Customers, we reject Turlock's recommendation for the reason stated by the ISO. The ISO states that this notification provision is essential in order to enable the ISO to know which

383/ EPUC/CAC at 11.

384/ ISO/PX September 16 Comments at 18-19.

Scheduling Coordinator is responsible for any Imbalance Energy attributable to the Eligible Customer's meter.

In response to EPUC/CAC's concern, we believe that, based on the ISO's response, the Annual Forecasting requirement is both reasonable and necessary. Eliminating this source of information may adversely affect the ISO planning abilities.

With regard to Southern Cities/Azusa and Banning's recommendation, we agree with the ISO that the ISO's duties should not be expanded to include the collection of bad debt of Scheduling Coordinators. The purpose of Scheduling Coordinators is to act as an intermediary between the ISO and customers and in this capacity it should be the responsibility of Scheduling Coordinators to recover amounts that they are owed.

We agree with BPA, ECI and others that the ISO should permit Eligible Customers to be represented by more than one Scheduling Coordinator. As recognized by the ISO/PX, an entity could potentially trade through one or more non-PX Scheduling Coordinators in the bilateral market to secure most of its energy requirements and also purchase stand-by or any additional requirements through the PX, which is another Scheduling Coordinator. 385/ We recognize that for many Market Participants, the ability to trade through more than one Scheduling Coordinator is an essential feature that will enable them to efficiently procure and utilize various resources. However, as noted by the ISO, the ability of a customer to utilize more than one Scheduling Coordinator depends on the development of the proper software and development by Scheduling Coordinators of rules for the allocation of trades through a single meter. 386/ Consistent with our earlier discussion, we require the ISO to inform us on the progress of the software development. To the extent that the ISO anticipates that the software will not be ready by the start of ISO operations, the ISO should promptly notify the Commission and request whatever extensions are necessary. In addition, we direct the ISO to coordinate efforts with all interested Scheduling Coordinators in the development of rules for allocating trades through a single meter. In addition, the ISO should address the concerns raised by commenters with regard to the coordination among competing entities and the exchange of sensitive market information. The ISO must be involved in these efforts in order to ensure that whatever rules are developed are consistent with the ISO's scheduling, metering and other protocols. We emphasize that we consider the development of the necessary software and trade

385/ ISO/PX June 23, 1997 Reply Comments at 258.

386/ ISO/PX Responses to Requests for Additional Information, Question 40 page 25.

rules to be a critical priority of the ISO that should be accomplished in as quick a time frame as possible.

Numerous parties oppose the ISO's restrictions on Inter-Scheduling Coordinator trades. The ISO has proposed modifications to the ISO and PX Tariffs to address these parties' concerns. We agree with the parties that trades between Scheduling Coordinators should not be restricted to a single zone. The ISO apparently does not contest this issue. The ISO states that the originally proposed tariff language was unclear. The ISO states that the reason a transaction must be deemed to take place within a single, specified zone is to avoid any uncertainty as to the Scheduling Coordinator responsible for paying Usage Charges in the event of congestion between zones. 387/ We interpret the ISO's proposed language to mean that once the Inter-Scheduling Coordinator trade is deemed consummated in a single zone, the purchasing trader is then responsible for scheduling the transmission of its purchased energy to the proper zone. Therefore, the purchasing trader will be responsible for all Usage Charges associated with transmitting its purchase. We find that the ISO and PX's revised language for Section 3.4.7.3 of the PX Tariff and Section 2.2.6.4 of the ISO Tariff to be unclear on this point. Moreover, we find that the parties to the Inter-Scheduling Coordinator Trade may wish to assign any applicable Usage Charge to either the selling Scheduling Coordinator or the purchasing Scheduling Coordinator. As long as the ISO is notified as to which Scheduling Coordinator will be responsible for paying any applicable Usage Charge, parties to a trade should be permitted to assign the Usage Charges to either party. We direct the PX to revise Section 3.4.7.3 of the PX Tariff to state as follows:

> Each Inter-Scheduling Coordinator Trade shall be treated as an export schedule in the Balanced Schedule of the selling trader and as an import in the Balanced Schedule of the purchasing trader. The Scheduling Coordinators which are parties to the Inter-Scheduling Coordinator Trades shall specify a single Zone in which the Energy transaction is deemed to take place. The parties to the Inter-Scheduling Coordinator Trade must notify the ISO, at the time they submit their schedules, as to which Scheduling Coordinator will be responsible for payment of applicable Usage Charges.

In addition, we direct the ISO to revise Section 2.2.6.4 of the ISO Tariff to state as follows:

> Billing and settling an Inter-Scheduling Coordinator Trade shall be undertaken in accordance with the

387/ ISO/PX September 16 Comments at 18-19.

> agreement between the Scheduling Coordinators who are parties to that trade, provided that they shall specify a single Zone within which the trade is deemed to take place. The parties to the Inter-Scheduling Coordinator

Trade must notify the ISO, at the time they submit their schedules, as to which Scheduling Coordinator will be responsible for payment of applicable Usage Charges.

We agree with BPA that Sections 2.5.20.1 and 2.5.28 of the ISO Tariff should be amended to provide that a Scheduling Coordinator's Operating Reserve requirement be reduced by the amount of system firm capacity purchased from outside the ISO Control Area consistent with all WSCC reliability standards. The ISO has appropriately provided for the exclusion of firm purchases from an outside control area with regard to its own provision of ancillary services 388/ and should extend the exclusion to Scheduling Coordinators' Self-Provided Ancillary Services. As noted by BPA, the ISO has provided no justification for this disparate treatment. Moreover, we note that the ISO will be able to verify a Scheduling Coordinator's purchase of firm resources from a neighboring control area through the information requirements of Section 2.5.20.6 of the ISO Tariff. However, we find that a Scheduling Coordinator must demonstrate that it has firm transmission arrangements in place for the delivery of Operating Reserves or any other Ancillary Service to the interconnection point with the ISO Controlled Grid. We direct the ISO to add a subpart (f) to ISO Tariff Section 2.5.20.7 which states:

(f) for self-provided Ancillary Services delivered from another control area, that the Scheduling Coordinator has arranged for the firm transmission of the Ancillary Services to the point of interconnection between the other control area and the ISO Controlled Grid.

We disagree with BPA that the Commission should require the ISO Tariff to explicitly state that the ISO will satisfy particular WSCC criteria. Section 2.3.1.3.1. of the ISO Tariff clearly provides that the ISO shall satisfy criteria no less stringent than those established by WSCC and NERC.

With regard to PG&E's concerns over the requirement to maintain an operating reserve equal to the total amount of interruptible imports scheduled by a Scheduling Coordinator, we agree that language should be added to the ISO Tariff to provide that only those Scheduling Coordinators that are importing interruptible energy will be charged for the ancillary service

388/ See ISO Tariff Section 2.5.3.2.

requirements associated with that energy. We direct the ISO to make conforming tariff changes. In addition, we are concerned with PG&E's statement that the systems being developed will not support the requirement to maintain an operating reserve requirement equal to the total amount of interruptible imports. As we stated previously, to the extent the ISO anticipates that the software will be unable to accommodate certain of its proposed features, the ISO should notify the Commission and keep

us informed on future developments. We direct the ISO to file a status report on this issue before the ISO Operations Date. To the extent the ISO's systems will be unable to support the above-stated reserve requirement, we direct the ISO to file a procedure, consistent with PG&E's "work around" suggestion, that will enable the ISO to accurately account and track the reserve requirement associated with interruptible energy imports.

We reject IEP's recommended changes to ISO Tariff Section 20.3.2 to add a broad array of information to be treated as confidential by the ISO. IEP has provided insufficient justification for its proposed changes.

We reject EPUC/CAC's recommendation that the ISO's security requirements for Scheduling Coordinators be reduced. First, the ISO Tariff provides that an ISO Security Amount will be required only for a Scheduling Coordinator that does not maintain an Approved Credit Rating. Second, we find that the ISO's requirement that all Scheduling Coordinators maintain a security amount that is greater than the Scheduling Coordinator's estimated aggregate liability for all charges for that trading day is reasonable and is consistent with our Order No. 888 requirements. In Order No. 888 we stated that a Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the service a letter of credit as security to meet its responsibilities and obligations under the Tariff. 389/

Other ISO Tariff Issues

Section 2 - ISO Operations

Contested Issues as Identified by the ISO/PX

BPA contends that there is a mismatch between the timing of the ISO scheduling process and BPA's scheduling process. Specifically, BPA accepts reserved schedules no later than 10:00

389/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,937.

am of a pre-schedule day whereas the ISO pre-schedule process concludes at 3:00 p.m. 390/

Turlock contends that the ISO should have no more than a right to request to use a UDC's Load curtailment program, rather than the right to use the program as spelled out in ISO Tariff Section 2.3.2.8. 391/ Turlock contends that this right will reduce the value of that program to the UDC. Turlock proposes that the ISO should have no more than a right to request Load curtailment, even in the event of a System Emergency. 392/

Western contends that PG&E has incorrectly asserted that

systems such as that of Western are not qualified to be considered as a Metered Subsystem. 393/

Southern Cities/Azusa and Banning contend that an Operator obliged to comply with an ISO order under ISO Tariff Section 2.3.3.5.3 should be able to call on the ISO to justify its instructions after the fact. Under Section 2.3.3 of the ISO Tariff the ISO, acting through the ISO Outage Coordination Office, has the duty to coordinate and approve all Maintenance Outages of facilities comprised in the ISO Controlled Grid. Each Operator is required to provide to the ISO by October 1 each year a schedule of all planned maintenance of ISO controlled facilities to be undertaken by the Operator during the following calendar year. Section 2.3.3.5.3 entitles the ISO to reject any requested Maintenance Outage where it considers that this is likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid.

June 23, 1997 ISO/PX Response

390/ September 2, 1997, Comments of BPA at 98-100. The issue is also brief referred to by PG&E at 4.

391/ Section 2.3.2.8 of the ISO Tariff provides that the ISO may utilize UDCs' load curtailment programs.

392/ September 2, 1997, Comments of Turlock at 41.

393/ July 22, 1997 Comments of Western at 19. We note that ISO Tariff, Appendix A, Master Definitions Supplement defines an MSS as:

> A system subsumed within the ISO Controlled Grid and encompassed by revenue quality meters which allows for Literal Self Provision of Ancillary Services and the bidding and sale of Ancillary Services and Energy to the PX and ISO from a System Unit.

The ISO notes that its scheduling process will be concluded by noon only if there is no Congestion. Further, the ISO states that the scheduling requirement does not affect those BPA customers which are holders of Existing Rights or Non-Converted Rights under Existing Contracts and may apply only to those who hold Converted Rights.

The ISO contends that both from a technical point of view and from a software development point of view it would be extremely difficult to shorten the timing of the scheduling process as proposed by BPA. The ISO suggests that a possible solution would be for BPA to extend its scheduling deadline.

In conclusion, the ISO states that the matter continues to be discussed in a WSCC task force and the ISO continues to participate in those discussions. The ISO will consider any

recommendation that is forthcoming from the WSCC.

With regard to the concerns raise by Southern Cities/Azusa and Banning, the ISO states that it must have ultimate control over outage planning to enable it to discharge its obligation to ensure the efficient use and reliable operation of the ISO Controlled Grid. Because of these obligations, the ISO maintains that the proposed modifications would undermine its authority. 394/ In response to Turlock's concerns regarding the ISO's use of a Utility Distribution Company's Load Curtailment Program, the ISO states that it has amended this provision to clarify that the ISO's right to direct the use of such programs would be limited to System Emergencies. The ISO contends that a right merely to request a UDC to implement its Load curtailment program will not be sufficient to enable the ISO to maintain system reliability in emergency circumstances. The ISO states that the limitation on the ISO's right to direct implementation of Load curtailment by the UDC during System Emergencies (which is a defined term) should protect the value to the UDC's Load curtailment program. 395/

September 2, 1997 Comments

BPA states that the ISO has amended its Tariff to close schedules at 1:00 p.m., and while this is a step in the right direction, the deadline is still inappropriate because it does not match WSCC practices. 396/

394/ ISO/PX June 23, 1997 Reply Comments at 241.

395/ ISO/PX June 23, 1997 Reply Comments at 245.

396/ BPA at 14.

In addition, BPA recommends that Sections 2.2.11.2.2 and 2.2.11.2.6 be amended to include after the term "Generating Units" the phrase "or system resources." Also, BPA recommends that Sections 2.2.13.3.1.1. and 2.2.13.3.1.3 of the ISO Tariff be revised to include after the term "Generating Units" the phrase "or source control area." BPA states that these revisions are necessary to incorporate the revisions to ISO Tariff Section 2.5 and PX Tariff Section 3.3.2 (which would accommodate the sale of generation from system resources located outside the ISO control area).

Southern Cities/Azusa and Banning recommend that ISO Tariff Section 2.2.4.6.1 be modified by adding the phrase, "by an entity subject to the jurisdiction of the FERC" at the end of the first line, to preserve the jurisdictional status of entities not subject to the Commission s jurisdiction. 397/

Southern Energy recommends that the ISO dispatch rules be amended to reverse the order of dispatch so that price sensitive demand bids are dispatched ahead of non-price sensitive

interruptible UDC load. Similarly, the California Commission contends that the dispatch order when the ISO intervenes to restore the grid in a system emergency, under ISO Tariff Section 2.3.2.3.2, may lead to inefficient results. The California Commission states that there is no reason to require that all generation, regardless of price, should be dispatched prior to curtailing price-responsive load, and that the provision could lead to gaming. 398/ Redding contends that ISO Tariff Section 2.3.2.8 requires revision because it requires UDCs to provide load management service which the UDC may no longer be able to provide, due to its lack of control of Load. Redding points out that in the restructured environment, the energy service provider and the wires service provider will not be able to freely exchange information. Therefore, the UDC will not have knowledge of Load management options.

DWR points out that the time line in Appendix C of the ISO Tariff to submit schedules does not match the revisions to Section 2.2.12 of the ISO Tariff. 399/

DWR recommends that Section 2.3.4.3 of the ISO Tariff be amended to allow self-approval of Regulatory Must-Run by a state or federal agency, since they are not subject to a Local Regulatory Agency.

397/ Southern Cities/Azusa and Banning at 17.

398/ California Commission at 33-34.

399/ DWR at 41.

BPA recommends that the Commission require the ISO to clarify the tariff so that only Market Participants within the ISO s control area are subject to ISO control. According to BPA, Sections 2.3.1.2.2, 2.3.1.3.1, and 2.3.2.1 of the ISO Tariff, continue to afford the ISO broad authority over all Market Participants.

BPA requests that Commission require the ISO to establish and file with the Commission a market-based methodology for determining the Administrative Price for energy and other services during a period of intervention, as described in Section 2.3.2 of the ISO Tariff. BPA requests that this filing be made subject to Commission review and approval. 400/

Commission Response

Section 2.2.8 of the ISO Tariff states that:

The scheduling process by nature will need constant review and amendment as the market develops and matures and, therefore, is subject to change.

This Section also provides that prior to the ISO Operation

Date the scheduling procedures will be reviewed by the WSCC to ensure compatibility with the WSCC standards and to achieve an acceptable regional process. We find that the ISO Tariff adequately complies with our open access tariff. In Order No. 888, the Commission recognized that by nature the scheduling process is complex and subject to differing regional practices that are consistently adhered to by the Transmission Provider. 401/

In addition, we note that BPA and members of the WSCC continue to work with the ISO regarding this issue. Rather than ordering the ISO to conform its tariff to fit BPA's historical practices, the Commission supports the ongoing collaborative process as the best alternative to achieve a technically workable practice.

We note the Southern Cities have agreed that an Operator is obligated to comply with an ISO order. Southern Cities simply request that the Operator be allowed to call on the ISO to explain its instruction after the fact. We do not see this request as undermining the ISO's authority. Rather, the request allows the flow of useful information between Operators. Therefore we require the ISO to amend Section 2.3.3.5.3 to allow

400/ BPA at 23.

401/ See Section 13.8 of the Pro Forma Transmission Tariff.

an Operator to request after-the-fact explanation of ISO instructions.

With the added clarification, providing that a Load curtailment program will be utilized only in emergency circumstances, Section 2.3.2.8 of the ISO Tariff is accepted. For the reasons stated by the ISO, we do not agree with Turlock's position. To ensure the reliability of the ISO Controlled Grid, the ISO must have the ability to direct a UDC to implement its load curtailment program. With regard to Redding's concerns that ISO Tariff Section 2.3.2.8 requires UDC's to implement load curtailment programs which the UDC may no longer be able to provide, we find that this is a matter to be discussed between the ISO and the UDC. To the extent a UDC does not have an operable load curtailment program the ISO obviously will not be able to require that UDC to implement it.

We reject Southern Energy's and the California Commission's recommendation that the ISO's dispatch rules be amended to provide that the ISO will consider price when dispatching generation and load in response to System Emergencies. The ISO's proposal is consistent with standard industry practice. Moreover, we do not want to limit the ISO's ability to respond quickly and effectively to a System Emergency. The ISO must be able to dispatch the generation and curtail load that will enable the ISO to maintain or restore system stability. In most cases, the location and operating characteristics of individual loads and generators will be the factors that determine whether a

generator is dispatched or load is curtailed. Introducing price into that determination will unnecessary complicate the ISO's procedures and could delay the restoration of the ISO Controlled Grid.

We disagree 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.

We agree with BPA that the ISO must file a method for determining the Administrative Price that will be established for energy and other services during an ISO intervention in the market as per Section 2.3.2 of the ISO Tariff. On compliance with this order, we direct the ISO to file a proposal for establishing the Administrative Price to become effective when ISO operations commence.

Section 4- Relationship Between ISO and UDCs

SMUD contends that the ISO and Energy service providers should be required to provide peak Demand meter data to the serving UDC. SMUD argues that the ISO and Energy service providers should be required to provide peak Demand meter data to the serving UDC which will require that data to appropriately plan and serve distribution customers reliably. 402/

DWR comments that the ISO must consult with all market participants, rather than just "UDCs or other entities, at the ISO s discretion" prior to subjecting parties to load curtailments under the electrical emergency plan pursuant to section 4.5.1 of the ISO Tariff. 403/

June 23 1997 ISO/PX Reply Comments

In response to SMUD, the ISO notes that while a UDC's need for meter data for planning is understandable, the ISO's role in relation to prescribing the uses of and dissemination of meter data should be limited to data used for purposes of the ISO Controlled Grid and not for purposes related to distribution systems. In particular, the ISO states that it should not prescribe the third parties to which meter data should be distributed as it may then be requiring a party (for example, a Scheduling Coordinator) to supply meter data to a competitor (for example, a UDC that is also a Scheduling Coordinator). In any event, the ISO argues, the local regulatory body with authority over distribution and retail access is the appropriate body to prescribe how such meter data should be shared. 404/

Commission Response

We agree with the ISO/PX that the ISO should not be required to provide demand meter data to third parties. We agree with the ISO that such data may be sensitive and that the ISO is not responsible for supplying such data to a UDC in order for the UDC to plan and serve its distribution customers. Therefore, we reject SMUD's recommendation.

We reject DWR's recommended changes to Section 4.5.1 of the ISO Tariff. The Electrical Emergency Plan (EEP) referenced in Section 4.5.1 of the ISO Tariff is developed in consultation with UDCs and discussions regarding its implementation are appropriately limited to the ISO and the relevant UDC. To the

402/ June 6, 1997, Comments of SMUD at 45.

403/ September 2, 1997, Comments of DWR at 40.

404/ ISO/PX June 23, 1997 Reply Comments at 272.

extent the ISO believes that it is necessary to involve other entities in the implementation of the EEP, Section 4.5.1 provides it with that discretion. We find DWR's recommended change unnecessary.

Section 5 - Relationship Between ISO and Generators

Under Section 5.5.1 of the ISO Tariff each Participating Generator is obliged to notify the ISO of its planned maintenance schedules. The notification is to be made for information purposes only, on an annual, quarterly and monthly basis. Changes in the maintenance schedule which would involve a unit being taken out of service on less than one month's notice must be reported to the ISO as soon as reasonably practicable. Where a change to the schedule would result in a unit being taken out of service on less than 7 day's notice, the ISO's consent must first be obtained.

Contested Issues as Identified by the ISO/PX

SoCal Edison argues that late changes to maintenance schedules should simply require ISO notification and not ISO consent. 405/ SoCal Edison suggests that price signals should be sufficient to ensure reliability and, if not, any Generating Unit which is sufficiently important for maintaining system reliability should have been designated as a Reliability Must-Run Unit.

EPUC/CAC contend that the ISO's right to monitor Generator performance in providing of Ancillary Services is too broad and suggest that the right to monitor should not extend beyond the interconnection point between the Generator and the ISO Controlled Grid. EPUC/CAC argue that the ISO Tariff gives the ISO too much power to investigate Generator performance. 406/

June 23, 1997 ISO/PX Response

The ISO notes that it is required under the Restructuring Legislation to ensure efficient use and reliable operation of the ISO Controlled Grid consistent with Applicable Reliability Criteria. The ISO Tariff has been drafted so that the ISO has some control over late changes to planned Generating Unit outages. The ISO can only object to changes to an outage schedule if the reliability or security of the system will be

405/ SoCal Edison at 18.

406/ EPUC/CAC at 52.

compromised. The ISO/PX state that at its meeting on June 17, the ISO Governing Board rejected the SoCal Edison proposal. 407/

In response to EPUC/CAC, the ISO states that the detailed procedures for monitoring and testing the performance of suppliers of Ancillary Services, including Generators, have yet to be fully developed. The ISO states that it will not undertake unnecessary monitoring and that it will define its monitoring rights as clearly as possible in its protocols. The ISO contends however, that it is not appropriate at this stage to limit the ISO's monitoring powers until it has gained sufficient operating experience to establish what is needed. 408/

September 2, 1997 Comments

BPA requests that the Commission direct the ISO to clarify that the definition of Participating Generators in the Master Definition Supplement is limited to Generators located in the ISO Control Area and excludes sellers located outside the ISO Control area. 409/ (The ISO Tariff combines the definitions of Participating Seller and Participating Generator). This, states BPA, creates an ambiguity insofar as Participating Generators can be interpreted to include Generators and Sellers of energy and other services in the California market. BPA states that the obligations and role of a Participating Generator are not appropriate for sellers and generators outside the ISO control area.

Commission Response

We believe that the ISO has adequately supported the need to control last minute changes to planned generator outages. We agree that this control is necessary for reliability reasons and therefore we will not adopt SoCal Edison's proposed modification.

We find that 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.

We reject BPA's request to define Participating Generators as generators located within the ISO Control Area. As we stated

407/ ISO/PX June 23, 1997 Reply Comments at 240.

408/ ISO/PX June 23, 1997 Reply Comments at 249.

409/ BPA at 23.

above, 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. Market Participants are defined to include Participating Generators.

Section 10 - Metering

Contested Issues Identified by the ISO/PX

Turlock contends that Section 10 of the ISO Tariff gives the ISO unnecessary authority over metering facilities and data acquisition. 410/ Turlock argues that the historical operation of utilities should be respected and that the ISO's access to data should be limited to that which is reasonably necessary to fulfill its responsibilities as Control Area operator. 411/

June 23, 1997 ISO/PX Response

The ISO argues that its authority under the ISO Tariff over metering facilities and data acquisition is not excessive given its billing and settlement responsibilities. The ISO argues Turlock's reference to the ISO's role as Control Area operator is too narrow and does not consider the ISO's other responsibilities under the new model.

The ISO notes that the California Commission recommends that the ISO be authorized to require the installation of real-time operational (rather than Settlement) metering. 412/ The ISO proposes to make the necessary amendments to the ISO Tariff in a subsequent compliance filing to implement this recommendation.

September 2, 1997 Comments

Turlock notes that the ISO's compliance filing contains a new limitation in Section 10.6.2.1 of the ISO Tariff which may address its concerns. However, Turlock notes that this revision contains two new terms (Scheduling Coordinator Metered Entity and Metered Entity) which are not defined. Turlock requests that the ISO provide further clarification. SoCal Edison, DWR and

410/ ISO/PX June 23, 1997 Reply Comments at 273.

411/ Turlock at 45.

412/ California Commission at 62-64.

SDG&E support the need for clarification. 413/ DWR, SDG&E, and SoCal Edison note that the Master Definitions Supplement needs to include Scheduling Coordinator Metered Entity, which is referred to in Section 10.6 of the ISO Tariff. 414/

SoCal Edison argues that ISO Tariff Section 10.2.3 does not adequately identify documents used to govern the development of actual meter standards and requirements. SoCal Edison suggests amending Section 10.2.3 to add the additional documents, as listed in its comments. 415/

DWR also argues that ISO Tariff Section 10.1 should not include a reference to Tie Point Meters because they are already included in the definition of ISO Metered Entities.

SoCal Edison recommends that sections 10.2.5 and 5.2.3.1 of the ISO Tariff be amended to ensure that market participants have access to meter data to ensure that ISO and PX settlements are correct. SoCal Edison suggests adding ISO Metered Entities to the listing of entities that may access the system database for meter data contained in ISO Tariff Section 10.2.5. SoCal Edison also suggests adding the following language to PX Tariff Section 5.2.3.1: 416/

> The PX shall poll the ISO meter data acquisition and processing system, in accordance with ISO protocols, to obtain Meter Data that the ISO collects directly and shall provide this [sic] data to PX customers when requested by those customers. The PX shall also poll the ISO meter data acquisition and processing system for Meter Data it needs for its own uses, if authorized by the applicable Metered Entity.

PG&E recommends that ISO Tariff Sections 10.2.4 and 10.6.6.2 be clarified to indicate whether the End-Use Meters of ISO Metered Entities and Scheduling Coordinator Metered Entities are grandfathered if they are in place on the ISO Operational Date. PG&E believes that the ISO intended to grandfather both end use

413/ SoCal Edison's September 2, 1997 Comments at 14.

414/ DWR states that a Scheduling Coordinator Metered Entity is an End Us located within the boundaries of the ISO Controlled Grid or an interconnected distribution system. SoCal Edison proposes defining Scheduling Coordinator Metered Entity as "An Entity not required by ISO Metering Protocol Documents to send meter data directly to the I

415/ SoCal Edison at 15.

416/ SoCal Edison at 16.

ISO Metered Entities and Scheduling Coordinator Metered Entities, and recommends revisions to make that clear. 417/

PG&E requests that ISO Tariff Section 10.6.2.3, Profiled Meter Data, be deleted, because the ISO cannot verify that the sum of Profiled meter data equals the aggregate data submitted by the ISO. According to PG&E, the ISO is not in a position to access and apply Distribution Load Factors, which it would require to apply to the aggregated load data. PG&E also requests elimination of a similar requirement in ISO Tariff Section 5.1.2.3, with respect to cumulative meter data. 418/

SDG&E notes that the August 15 Filing revised ISO Tariff Section 10.6.5.5 to eliminate the inspection, testing and auditing of metering installations of all end users. As revised, the ISO's inspection and audit authority is limited to Scheduling Coordinator Metered Entities connected to the ISO Controlled Grid from the meter data server to the metering system(s). SDG&E proposes revisions to ISO Tariff Section 10.6.5.5 to eliminate these new restrictions. 419/

IEP recommends that the ISO Tariff should expand audit, testing and meter certification exceptions. 420/ IEP argues that the End Use Meter Standards contained in Appendix J of the ISO Tariff afford UDCs undue authority to establish and enforce metering requirements applicable to Scheduling Coordinators. IEP believes that the ISO should carefully limit UDC involvement in establishing meter standards. IEP recommends such standards be established by the Commission or local Regulatory Authorities instead. 421/

Redding objects to the fact that the ISO would be entitled to install equipment at any point within the UDC s metered Sub System to meet its service obligations, under ISO Tariff Section 4.8.4.1. This authority should not be permitted without full knowledge and consent of the UDC/Metered Subsystem, according to Redding, because the ISO s actions could preclude future design options and cause future financial burdens on the UDC. Redding

417/ PG&E at 12-14.

418/ PG&E at 3-4.

419/ SDG&E at 3-4.

420/ IEP at 8.

421/ IEP at 7.

proposes appropriate revisions to the tariff to more fairly balance these concerns. 422/

Commission Response

We agree with PG&E that the ISO should grandfather End-Use meters of ISO Metered Entities and Scheduling Coordinator Metered Entities. We direct the ISO to clarify the Tariff provisions consistent with PG&E's suggested language.

We are not now prepared to grant PG&E's request to delete ISO Tariff Section 10.6.2.3, Profiled Meter Data. PG&E's main contention is that the ISO is not in a position to access certain information and that the ISO systems do not have the capability of handling these data. Once the ISO's systems are fully developed and operational, PG&E may review its request to remove this section once it is determined definitively that the ISO has no ability to use these data for settlement or other purposes.

SDG&E's argument to expand the ISO's responsibility to include inspection and auditing of all end-user meters is not well supported. We are not now prepared to expand the ISO's responsibility in this manner. Scheduling Coordinators appear to be more properly situated to perform this function.

IEP has not adequately supported its request to expand the audit, testing and meter certification exemptions. At this time we will defer to the ISO and UDC meter standards proposed in ISO Tariff Appendix J. Imposing different standards could have severe cost consequences. We expect the ISO to ensure UDC metering requirements are applied fairly and in a non-discriminatory manner.

We do not believe that Redding's proposal to prohibit equipment installation if it causes existing equipment to be operated beyond nameplate ratings is necessary. We note that ISO Tariff Section 4.8.4.1.1 does not allow equipment installations that "have a negative impact on the reliability of the service."

We reject Turlock's recommendations. Under the new model, the ISO will not only operate as the control area operator, but it must also perform billing and settlement functions. Therefore, it is reasonable that the ISO have broad access to data acquisition and metering facilities. In its compliance filing we will require only that the ISO provide definitions of the new terms identified by Turlock.

422/ Redding at 24-25. See also TANC at Appendix A.

We reject DWR's recommended change to Section 10.1 of the ISO Tariff. We find that the reference in ISO Tariff Section 10.1 to Tie Point Meters is reasonable and provides clarity.

We reject SoCal Edison's recommendation that Section 10.2.3 of the ISO Tariff be amended to add references to certain technical documents that will govern the development of actual meter standards. We find that it is unnecessary to amend the referenced section. Section 10.2.3 of the ISO Tariff appropriately references the meter standards included in Appendix J to the ISO Tariff.

We agree with SoCal Edison's recommendation to permit ISO Metered Entities to access the ISO administered system database for meter data. Section 10.2.5 of the ISO Tariff provides that the ISO's revenue metering data acquisition and processing system will collect Meter Data made available by ISO Metered Entities. While we recognize that the ISO will settle and bill through each ISO Metered Entities' respective Scheduling Coordinator, we see no harm in providing ISO Metered Entities with access to the database. We note that Section 10.2.5 already provides access to, "other authorized users as identified in the relevant meter service agreement." We direct the ISO and PX to make conforming changes to their tariffs as suggested by SoCal Edison.

Section 15 - Uncontrollable Forces

IEP notes that the definition of Uncontrollable Force in Section 15 of the ISO Tariff and the Master Definitions sections are inconsistent. 423/

We agree with IEP that the definitions of Uncontrollable Force contained in Section 15 of the ISO Tariff and in the Master Definition Supplement are inconsistent. We direct the ISO to conform the definition of Uncontrollable Force in the Master Definitions Supplement to match the first paragraph of Section 15 of the ISO Tariff.

Miscellaneous Issues

EPUC/CAC support the use of interruptible Direct Access transactions during the transition period, but requests that the Commission require the ISO to clarify and explain why this program is referred to in Appendix III, Figure 2, as a "staged feature." EPUC/CAC also requests more detailed protocols in the

423/ IEP at 9.

tariff regarding the interruption process and a technical conference in early 1998 to develop the proposal. 424/

Oakland argues that the disposition of the 115 kV electric line extending between PG&E s Substation C and the U.S. Navy s Davis Substation and the Port of Oakland s Cuthbertson Substation (115 kV line) remains at issue until the Commission acts on the Motion to Dismiss, 425/ PG&E removes the 115 kV line from designation on its filed maps, or the ISO agrees to relinquish control over the 115 kV line. Although Oakland states that it has reached an agreement with PG&E on the issue, and no party has objected, the filings do not reflect this resolution. Oakland also complains that the ISO has not provided a date when it will specify which facilities are required to be under its operational control in its Staging Plan, contained in Appendix II of the August 15 Filing. 426/

PG&E recommends that the definition of Tie Point Meter contained in the Master Definitions Supplement be revised to state: "A Revenue Meter, which is capable of providing Settlement Quality Meter Data, at a Scheduling Point or at a boundary between UDCs within the ISO Controlled Grid." According to PG&E, the revision is necessary because calculations of transmission losses and Unaccounted for Energy are by UDC Service Area. 427/

Commission Response

We agree with EPUC/CAC that the ISO should clarify why the ISO's and PX's treatment of Interruptible Imports is referred to as a staged feature. We also direct the ISO to provide information on the interruptible process. We reject EPUC/CAC's request for a technical conference on such a limited issue.

We agree with PG&E that the definition of Tie Point Meter should be amended to recognize the meters located at an ISO/UDC boundary. With respect to Oakland's concerns, we direct the ISO, PG&E and Oakland to clarify the status of the 115kV line on the ISO Register.

424/ EPUC/CAC at 17.

425/ See Motion for Dismissal of Facility Designation, filed July 8, 1997, these proceedings (Motion for Dismissal).

426/ Oakland at 6.

427/ PG&E at 14.

F. Liability and Indemnification

Section 14 of the ISO Tariff provides that the ISO will not

be liable for losses, damages, claims, etc. arising from its performance or non-performance of its obligations under the tariff except to the extent that its breach of the ISO Tariff provisions result in damage to property or death or injury to any person. Section 14.2 of the ISO Tariff further provides that the ISO shall not be liable to any Market Participant under any circumstances for any financial loss resulting from physical damage to property. Section 14.3 of the ISO Tariff provides that each Market Participant shall indemnify the ISO and hold it harmless against all losses, damages, claims, etc., from any act or omission of the Market Participant, except to the extent such loss results from the ISO's default under the ISO Tariff or negligence on the part of the ISO.

Section 9 of the PX Tariff contains identical liability and indemnification provisions. Section 22.4 of the Transmission Control Agreement contains similar indemnification provisions.

Contested Issues Identified by the ISO/PX

Certain Parties have argued that the ISO should indemnify the Market Participants in the same way as they are obligated to indemnify the ISO because there should be reciprocity between them. Specifically, they contend that the ISO Tariff Section 14.2 and the Transmission Control Agreement Section 22.4 provide for Market Participants and Participating Transmission Owners to indemnify the ISO, but there is no equivalent provision for the ISO to indemnify Market Participants. 428/

For example, ECI notes that ISO Tariff Section 14.1 provides that the ISO will be liable only for physical damage to property or personal injury or death, and not for consequential or indirect financial losses. ECI contends that this provision sets an unfair double standard under which Market Participants must completely indemnify the ISO against all losses arising out the acts of the Market Participants, while ISO liability is limited. ECI recommends that the provision be amended to require the ISO to be fully liable towards Market Participants and to allow Market Participants to recover financial damages in the event of ISO default or negligence. 429/ In support of its argument, ECI

428/ LADWP at 55-58; Turlock at 53; and ECI at 16-17.

429/ LADWP at 58; ECI at 17.

cites Pacific Interstate Offshore Company which was referred to by the Commission in Order No. 888: 430/

> the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.

In addition, LADWP argues that when transmission owners

operate under the direction of the ISO, it is unreasonable to hold the ISO harmless. LADWP contends that when carrying out ISO directives, the transmission owner is acting as agent for the ISO and, in that circumstance, should not shoulder liability for the consequences of following such directives. Therefore, LADWP proposes that the ISO Tariff be amended to provide that the ISO will indemnify the Participating Transmission Owner when the ISO issues an operating order to which the Participating Transmission Owner objects and compliance with the order causes damages. 431/

June 23, 1997 ISO/PX Reply Comments

The ISO/PX contends that the Commission examined the same arguments in Order Nos. 888 and 888-A regarding the indemnification provision of the pro-forma Tariff and stated:

> We have limited the indemnification portion of the provision so that it is now only the transmission customer who indemnifies the transmission provider from the claims of third parties. The customer is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from the provision of service to the customer under the tariff. [432/]

Also, the ISO/PX points out that the Commission re-emphasized its position on the same issue in Order No. 888-A. 433/

In response to LADWP s argument that "the basic premise of a competitive electric industry is the equitable apportioning of benefits and costs in a comparable way among participants" 434/ the ISO/PX states that this argument overlooks the fact that the

430/ 62 FERC □ 61,260 (1993).

431/ LADWP at 56.

432/ Order No. 888, FERC Stats. & Regs. □31,036 at 31,765.

433/ Order No. 888-A FERC Stats. & Regs. □31,048 at 30,301.

434/ LADWP at 57.

ISO is not obtaining any benefits to offset against the burden of indemnity and there is no comparable basis for imposing an indemnification obligation on the ISO, as expressly recognized by the Commission in Order No. 888-A. The ISO/PX contends that there is a fundamental difference between Market Participants and the ISO which justifies the different treatment. The ISO/PX states that it is a not for profit organization set up for the benefit of Market Participants; its activities are controlled and directed by Market Participants. Moreover, the ISO/PX contends that the greater part of the funds which it holds are held in trust for the benefit of Market Participants on the basis of the "pass through" of funds to and from the various Scheduling

Coordinators. Its administration costs will be recovered from Market Participants through the Grid Management Charge.

The ISO/PX also argues that since the ISO will have no funds available to meet claims under an indemnity requirement, it would have to rely either on insurance or self insurance. According to the ISO/PX, indemnities expose the ISO to claims for consequential losses. The ISO/PX argues that obtaining insurance to cover for such claims would be extremely difficult, expensive, and the cost of insurance and of funding the indemnity would have to be spread among all Market Participants. The alternative, self insurance, would be equally burdensome and would, essentially, require the ISO to establish its own contingency fund or "captive" insurance company, again at great cost to Market Participants, according to the ISO/PX.

The ISO/PX argues that if the ISO were obliged to indemnify Market Participants completely, it would face the risk of an unquantifiable amount of liability towards an unquantifiable number of claimants. The ISO/PX claims that under the ISO Tariff (and the Transmission Control Agreement), as currently drafted, all Market Participants are treated equally. Further, the ISO/PX claims that the provision limits the exposure of each Market Participant under the indemnity it gives to the ISO. The ISO/PX argues that the one-way indemnity is designed to act as an incentive on individual Market Participants to comply with the rules and to provide a self-executing mechanism to enable the ISO to seek redress on behalf of Market Participants to the extent of the ISO's liability to them. 435/

In response to ECI s argument, the ISO/PX states that in Pacific Interstate Offshore Company the Commission did not decide that an entity in the position of a transmission provider could not limit its liability for negligence. The ISO/PX argues that the Commission decided that such entity could not rely upon an indemnity from its customer to exclude its liability for negligence. In fact, the ISO/PX argues, the ISO Tariff expressly

435/ ISO/PX June 23, 1997 Reply Comments at 264.

complies with the requirements set forth in that case and in Order No. 888 by providing that the Market Participant's obligation to indemnify does not arise in cases where the damage arises out of ISO's default or negligence. 436/

As to the proposed requirement for the ISO to be liable for financial loss, the ISO/PX responds that the ISO is not a profit organization and does not have funds to compensate Market Participants. Thus, the ISO will either rely solely on its insurance coverage for this purpose (to the extent it can obtain insurance on commercially reasonable terms)or the Market Participants must themselves fund it. Even if the ISO were permitted to recover these funds through the Grid Management Charge, it claims this would mean that the market would be burdened to support the financial loss caused by one participant. If the liability of the ISO were not limited as proposed, the

ISO/PX contends there would be no incentive on Market Participants to manage their affairs to minimize their loss or to limit their own liability to third parties. Moreover, the ISO/PX points out that the ISO is a neutral and independent service provider with no incentive or interest in getting things wrong. 437/ The ISO/PX views this is as one of the main reasons that this liability limitation has been utilized in other power pools and restructuring.

In response to LADWP's proposal to limit Participating Transmission Owner liability when acting on ISO directions, the ISO/PX states that Market Participants do not operate as agents of the ISO when they comply with the rules, protocols and procedures of the markets that the ISO administers (including rules relating to reliability). According to the ISO/PX, when the ISO issues instructions to ensure the reliability of the ISO Controlled Grid the ISO is acting on behalf of all Market Participants and compliance with ISO instructions is both necessary and prudent. The ISO/PX states that the only exceptions are compliance with instructions which endanger health or safety under Section 2.3.1.2.1 of the ISO Tariff and Sections 6.1.2 and 6.1.3 of the Transmission Control Agreement. In addition if a Market Participant were in receipt of an instruction from the ISO which the Market Participant exercising Good Utility Practice should know would cause physical damage, the Market Participant would be under a duty to warn the ISO if time permitted. 438/

436/ ISO/PX June 23, 1997 Reply Comments at 267.

437/ LADWP at 57 raises this issue.

438/ ISO/PX June 23, 1997 Reply Comments at 269.

In response to LADWP's query, "why it is not in the best position to equitably spread these costs [of losses or damages] among all ISO Grid users instead of requiring an individual Transmission Owner to bear a disproportionate amount of these costs," 439/ the ISO/PX responds that these provisions relate to costs incurred by a Market Participant or a third party as a result of an act or omission of the Participating Transmission Owner. Both the Transmission Control Agreement and the ISO Tariff are clear that if the ISO is in default or is negligent in giving the operating order, the Participating Transmission Owner will not be held liable. If, however, the ISO is not at fault and was not even negligent, either the Participating Transmission Owner will be at fault (in which case it is reasonable that it should be burdened by the resulting costs) or the damage was caused by an accident or breakdown or other event which would have been a risk that the Participating Transmission Owner normally bears as part of its day-to-day operations. The ISO/PX contends that this is not a risk which should be shifted to the ISO.

September 2, 1997 Comments

DWR argues that ISO Tariff Sections 14.1 and 14.2 eliminate any liability for breach of contract or tort unless physical injury or damage results. According to DWR, this effectively eliminates liability for breach of contract and is unfair when compared with section 14.3 of the ISO Tariff, which requires Market Participants to indemnify the ISO for any losses, costs, or expenses arising from any act or omission, whether or not the act or omission was lawful or proper. DWR recommends that the ISO and PX be held to the same standards as any other private entity: They should be liable for breach of contract and for violations of their duties and obligations under the ISO Tariff. Moreover, DWR recommends that section 14.3 should require indemnification only when the Market Participant's actions are wrongful. In addition, since some governmental entities are prohibited by law from entering into indemnification agreements, section 14.3 of the ISO Tariff and Section 9.3 of the PX Tariff should be modified to include the phrase "to the extent permitted by law."

LADWP argues that although the ISO proposed minor modifications to the ISO Tariff, these only make the ISO liable for arbitration costs under ISO Tariff Section 13.3.14, and do not provide sufficient protection for Participating Transmission Owners. LADWP argues that the ISO should have a disincentive,

439/ LADWP at 56.

rather than the ability, to cause losses without any accountability. 440/

Commission Response

With minor clarifications, we find the ISO's and PX's proposed indemnification provisions to be reasonable. The ISO's and PX's proposal appropriately provides that Market Participants indemnify the ISO (or PX, as the case may be) from third party claims. It also appropriately limits the indemnification in cases of negligence on the part of the ISO or PX.

As noted by the ISO/PX, in Order Nos. 888 and 888-A we found that the transmission customer should indemnify the transmission provider from the claims of third parties. We stated that it is the customer that is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from provision of service to the customer under the tariff. Here, the ISO will be the transmission provider and therefore it is the Market Participants (as customers) that should indemnify the ISO, not vice versa. Therefore, we reject LADWP's, Turlock's and ECI's recommendation that the ISO reciprocally indemnify Market Participants.

We note that, consistent with Order Nos. 888 and 888-A, the ISO tariff provides that the Market Participants are not obligated to indemnify the ISO in cases where the ISO is negligent. However, also consistent with Order Nos. 888 and 888-A, the Market Participants should not be obligated to indemnify the ISO or PX for negligence or intentionally wrongful acts of the ISO or PX. Therefore, Section 14.3 of the ISO Tariff and Section 9.3 of the PX Tariff should be modified by adding the words "or intentional wrongdoing" after the word "negligence." We also agree with DWR that Section 14.3 of the ISO Tariff and Section 9.3 of the PX Tariff should be modified with the addition of the phrase, "to the extent permitted by law." We find that with this clarification the provisions will properly recognize governmental entities' limitations on entering into indemnification agreements. 441/

With regard to the liability provisions in sections 14.1 and 14.2 of the ISO Tariff and sections 9.1 and 9.2 of the PX Tariff, we find the ISO's and PX's proposed limitations on liability to be overbroad. The proposal appropriately provides that neither the ISO/PX nor the Market Participant will be in default of these

440/ LADWP at 35-36.

441/ We also direct the ISO to modify the relevant sections of the Transmission Control Agreement consistent with this discussion.

Tariff provisions if a force majeure event (called an "Uncontrollable Force" in the Tariff) occurs. But the proposal as drafted goes too far, in that it would also excuse the ISO or PX from liability in cases of negligence or intentional wrongdoing, except in cases where such actions result in personal injury or physical damage to the property of the Market Participants.

It is appropriate for the ISO or PX to be protected from liability that may occur when the ISO or PX is not negligent in the performance of its responsibilities under its Tariff. However, the ISO/PX contends that they are entitled to a broad exculpatory clause limiting liability, even in some situations where they have been negligent, because they are not-for-profit corporations that act on behalf of the Market Participants. We are not aware of any general principle of law that excuses entities from liability because of their not-for-profit status, and we note that Market Participants may also be not-for-profit entities. We believe that the determination of the ISO's or PX's liability in instances of negligence or intentional wrongdoing is best left to appropriate court proceedings, in which the parties will be free to advance any appropriate argument. We direct that sections 14.1 and 14.2 of the ISO Tariff and sections 9.1 and 9.2 of the PX Tariff be modified so as not to provide any limitation on liability of the ISO or PX in cases of their negligence or intentional wrongdoing.

We reject LADWP's proposal to limit Participating

Transmission Owner liability when acting on ISO directions and its proposal to spread the costs of damages resulting from the actions of a Participating Transmission Owner among all ISO Grid Users. To the extent the ISO is negligent in giving the proper operating orders to the Participating Transmission Owner, the Participating Transmission Owner will not be liable. If, however, the Participating Transmission Owner were negligent or in default, we do not find it appropriate to shift liability from the negligent party to the ISO or other Market Participants through a broad tariff provision. The Participating Transmission Owner's liability in such instances is best left to appropriate court proceedings.

G. Transmission Losses

Under Section 7.4 of the ISO Tariff, each Scheduling Coordinator would be required to ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses. To meet its responsibilities for Transmission Losses, a Scheduling Coordinator may either self-provide the required amount of energy in kind or purchase the required energy from the ISO at the Hourly Ex Post Price for Imbalance Energy.

A Scheduling Coordinator's responsibility for Transmission Losses could be either positive or negative, depending on its generator's effect on total system Transmission Losses. That is, a Scheduling Coordinator would be required to supply more energy from its generator than is consumed by its Demand (or purchase energy for Transmission Losses from the ISO) in instances where the generating unit's contribution increases system Transmission Losses. Conversely, the Scheduling Coordinator would be required to supply less energy from its generator than is consumed by its Demand (or sell an equivalent amount of energy to the ISO) in instances where the generating unit's contribution reduces system Transmission Losses.

Calculating a Scheduling Coordinator's responsibility for Transmission Losses is done through the use of a Generation Meter Multiplier, or GMM. The GMM is the percentage of a generator's output that may be used to meet its Demand. Thus for example, if a generator's GMM is .95, then the generator would use 95 percent of its output to meet Demand and the remaining 5 percent to cover Transmission Losses.

The percentage of a generator's output required to cover Transmission Losses is referred to as its Scaled Marginal Loss Rate, which is calculated in two steps. First, the Full Marginal Loss Rate for the generating unit is calculated, using a Power Flow Model to determine the effect on total system Transmission Losses of injecting an increment of Generation from the unit and serving an equivalent increment of Demand distributed pro-rata throughout the ISO grid. Thus, the Full Marginal Loss Rate attributed to a generator does not depend on the location of the actual load served by the generator as specified in the applicable bilateral contract. The same loss rate would be attributed to the generator whether the load it contracted with was located close to the generator or far away.

Second, the Full Marginal Loss Rate will be adjusted downward by the Loss Scale Factor, to arrive at the Scaled Marginal Loss Rate. The reason given for the second step -- scaling down the Full Marginal Loss Rate -- is that marginal Transmission Losses increase as line loadings increase, and thus

are greater than average Transmission Losses. As a result, if every generator were assessed the Full Marginal Loss Rate, the total amount collected for Transmission Losses would exceed the ISO s actual total Transmission Losses. The ISO proposes to adjust the amount of Transmission Losses assessed to each generator sufficiently so that the total amount collected will equal the ISO s actual total Transmission Losses. The percentage of adjustment needed -- i.e., the Loss Scale Factor -- may vary at different times, depending on the line loadings. But for any hour, the same Loss Scale Factor will be applied to each generator s Full Marginal Loss Rate to determine its Scaled Marginal Loss Rate.

Section 7.4.2.1 describes the procedures for calculating Loss Rates and GMMs. By 6 pm two days preceding a Trading Day, the ISO will calculate and post on WEnet an estimated GMM for each Generation bus, based on forecasts of total Demand, as well as Demand and Generation patterns. The ISO will continuously update the data used in the calculations as system conditions change. The ISO will determine the appropriate period over which each set of GMMs will apply; new GMMs need not be determined for each hour. The GMMs used

to determine loss responsibility will be those based on the last available forecast.

Section 7.4.3 describes a future modification. The ISO would be permitted to recalculate GMMs based on actual data on Generation and Demand after the fact and to use these ex post GMMs to determine each Scheduling Coordinator's loss responsibility. Any differences between ex post Transmission Losses and the estimated Transmission Losses would be settled as Imbalance Energy. However, ex post GMMs based on actual data would not be used in determining loss responsibility until the ISO can accommodate their calculation and the ISO gives 30 days notice posted on WEnet of its intent to use them.

Public Comments

Western contends that Unaccounted For Energy (UFE) losses should not be assigned to Scheduling Coordinators delivering to load only at transmission level. 442/ DWR argues that UFE losses should not be assigned to Scheduling Coordinators with ISO Grid level loads, which do not in DWR s opinion contribute to UFE as defined in the Master Definitions Supplement. DWR suggests that distribution level meters are the primary source of these errors and should be dealt with on the basis of specific meter test results. 443/ SoCal Edison argues that the provision for allocating UFE losses among Scheduling Coordinators, based on the ratio of each Scheduling Coordinator s non-hourly Metered Demand to the total non-hourly Metered Demand within the UDC Service Area, is incomplete, because ISO Tariff Sections 11.2.4.5 and 11.2.4.6 provide insufficient detail to compute the components of UFE necessary to determine how much each Scheduling Coordinator would pay. 444/

M-S-R argues that the Commission ignored numerous issues of fact in its July order, including whether the methodology for calculating Transmission Losses in Section 7.4 of the ISO Tariff accurately computes Transmission Losses. 445/ M-S-R proposes three modifications to the ISO loss calculation: (1) if there is congestion, losses for each Zone should be determined separately for each zone; (2) the pro rata increase in Generation should only be applied to the Load which the Scheduling Coordinator is serving; and (3) as to Scheduling Coordinators that are moving energy through the ISO Controlled

Grid on behalf of a non-Participating Transmission Owner load, the calculation should only recognize an increase in Energy at the node where the Energy is

442/ Western July 22, 1997 Comments at 13.

443/ DWR September 2, 1997 Comments at 41.

444/ SoCal Edison September 2, 1997 Comments at 13-14.

445/ M-S-R August 29, 1997 Request for Rehearing, at 12-13.

inserted into the ISO Controlled Grid and an increase at the node where it is withdrawn. 446/

ECI and CCEM oppose the ISO s proposal in Section 7.4.3 to base loss assessments on after-the-fact calculations. In their view, the proposal is unacceptable because it results in indeterminate and retroactively-applied charges. Instead, they argue, loss assessments should be determined ex ante. 447/ PECO, ECI, and CCEM argue that after-the-fact pricing of Transmission Losses under ISO Tariff Sections 7.4.3 and 11.2.4.1 creates uncertainty which is a barrier to market entry. 448/ ECI recommends that the provisions for after-the fact calculation and allocation of Transmission Losses be deleted from the Tariff. PECO recommends prospective pricing, based on historical data, and adjusted periodically to reflect actual experience. 449/

Metropolitan comments that the ISO transmission loss methodology has the potential to cause systematic bias in assigning loss responsibility because the methodology considers the location of generators, but not the location of loads, so distance is not accurately reflected. 450/

Commission Response

The ISO proposes a novel method for assigning Transmission Losses that appears to move in the direction of marginal cost pricing for transmission. It is important for market participants in California to face accurate transmission price signals, if restructuring and greater reliance on competitive energy markets are to realize their full economic potential. We share the concern of M-S-R and Metropolitan regarding how the assignment of Transmission Losses to individual participants is computed.

Despite our concerns, we will accept for now the ISO's proposal for calculating Transmission Losses. We do not know at this point how significantly the ISO's proposal for calculating Transmission Losses would differ from a full marginal cost price signal. The record has little information on the magnitude of marginal Transmission Losses in California, how substantially marginal Transmission Losses vary depending on conditions such as transmission direction and distance and line loadings, and how substantially the ISO's proposed calculations would differ from actual marginal Transmission Losses.

446/ Id. at 19.

447/ ECI September 2, 1997 Comments at 11-12; CCEM September 2, 1997 Commen at 5, 16.

448/ ECI September 2, 1997 Comments at 11-12; CCEM September 2, 1997 Comments at 16.

449/ PECO September 2, 1997 Comments at 3.

450/ Metropolitan June 6, 1997 Comments at 32.

Therefore, we will require the ISO to conduct a study and file a report by January 1, 1999. The report should evaluate the effects of the ISO's proposal for calculating and assigning Transmission Losses to individual Scheduling Coordinators, compared to a method that assigned to each Scheduling Coordinator the full marginal Transmission Losses associated with its actual scheduled transactions. The report should include a comparison of loss assignments (and their monetary value at applicable energy prices) under the two methods for a variety of transactions that reflect differences in distance and direction between the generator and its load, as well as differences in line loadings. After we receive the report, we will reevaluate the ISO's proposal for Transmission Losses.

Unaccounted For Energy (UFE)

Western and DWR argue that UFE losses should not be assigned to Scheduling Coordinators that deliver load at the transmission level. We note that the UFE losses are attributed to meter measurement errors, energy theft, statistical Load profile errors and distribution loss deviations. The ISO Tariff provides that once the necessary ISO software is developed, the portion of UFE losses attributable to Load profiling errors will be separately determined and allocated to those Scheduling Coordinators who use Load profiling (i.e.,Scheduling Coordinators who do not use time sensitive demand metering). Western supports this proposal. 451/ However, parties still object to the assignment of UFE losses that may include a distribution loss deviation component or an energy theft component to Scheduling Coordinators that schedule only at the Transmission level. While the distribution loss deviation component should arguably not be assigned to such Scheduling Coordinators, the quantification of this single component may not be feasible. We do not agree that Scheduling Coordinators scheduling at only the transmission level should bear no share of the other loss components because they are attributable to overall system conditions and do not lend themselves to any reasonable alternative assignment methodology. Therefore, we find that the ISO Tariff assignment of UFE losses is reasonable. Until the ISO implements the procedure for assigning Load profiling errors, we note that the clarification SoCal Edison requests (i.e., identifying the individual loss components) is premature.

After-the-Fact Loss Calculations

We will require the ISO to delete the portion of Section 7.4.3 of its Tariff that would, after 30 day's notice published on WEnet, allow the ISO to recalculate ex post Generation Meter Multipliers based on actual data, since the ISO does not intend to implement this provision on the date when ISO operations commence. Consistent with our other rulings in this Order on

staged matters, the ISO may refile this provision under Section 205 60 days before the ISO is prepared to implement it. The comments of ECI, CCEM, and

451/ Western September 2, 1997 Comments at 48.

PECO Energy regarding this feature are premature. The parties may raise the issue after the ISO files to implement this feature.

H. Overgeneration

Background

During the Phase I process, the California Commission identified a special class of generation -- must-take resources and hydro spill -- which would be excluded from the competitive market and which would be able to schedule generation through the PX without submitting a bid in the PX auction. Given this designation, the Phase I Filing recognized that during certain low demand hours there was a possibility that the amount of generation available from these generators might exceed total demand. To deal with this problem, the Phase I Filing included overgeneration procedures that specified how generation would be reduced in these circumstances.

In the March 31 and August 15 Filings, the ISO modified its definition of must-take to include resources identified by other Local Regulatory Authorities in addition to the California Commission, and included hydro spill in a larger category of must-run generation that is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. These changes were made in consideration of the must-run and must-take obligations of Scheduling Coordinators other than the PX, in the restructured California market.

August 15 Filing

The ISO/PX define Overgeneration as a condition that occurs when total demand in the PX is less than or equal to the sum of Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation in the Day-Ahead schedule or in the Real Time market. 452/ Overgeneration conditions in the Hour-Ahead Market are not defined.

Must-Take and Must-Run units are defined as follows: 453/

Regulatory Must-Take Generation are those resources, identified by the California Commission or other Local Regulatory Authority, that will not be subject to competition. They will be scheduled directly with the ISO through the relevant Scheduling Coordinator on a must-take basis. They include qualifying facility Generating Units, nuclear units and pre-existing power purchase contracts with minimum energy take requirements.

452/ August 15 Filing, Appendix A, Master Definitions Supplement. This definition is based on the understanding that there would be generat scheduled in the PX in addition to Regulatory Must-Take, Regulatory Must-Run, and Reliability Must-Run Generation.

453/ Id.

Regulatory Must-Run Generation is Hydro Spill Generation and other Generation that is required by law to fulfill certain requirements such as hydrological flow, environmental, water supply or solid waste Generation requirements.

Reliability Must-Run Generation are those resources identified by and under contract with the ISO to run when the ISO calls them for reliable operation of the ISO Grid.

Eligible Regulatory Must-Take/Must-Run Generation is Regulatory Must-Take or Regulatory Must-Run Generation that is owned or produced by a Participating Transmission Owner or UDC which has provided direct access to its End Use Customers and serves load in the ISO Control Area.

1. Day-Ahead Overgeneration Scheduling Procedures as Described in the August 15th Filing

Prior to the commencement of the Day-Ahead Scheduling process, the PX will inform the ISO of potential Overgeneration conditions. The ISO will use a variety of system information and forecasts to determine whether to invoke Overgeneration procedures during the Day-Ahead Scheduling process. Upon a determination by the ISO that Overgeneration conditions exist, the ISO proposes to implement a three-step process to resolve the Overgeneration condition. 454/

In the first step, the PX will be required to reduce scheduled Generation other than scheduled Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation in price order, i.e., with the most expensive generation reduced first, to a point that resolves the Overgeneration or to a point that all such Generation is completely eliminated from the schedule. If the Overgeneration condition has not been resolved, the ISO will proceed to step 2.

In step 2, certain non-PX Scheduling Coordinators, specifically those scheduled to serve Direct Access End-Users in Service Areas of Eligible Regulatory Must-Run and Eligible Regulatory Must-Take Generation, will be required to reduce scheduled Generation other than scheduled Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation. The ISO may first ask for voluntary reductions. If the reductions are not sufficient to resolve the Overgeneration, the ISO will order a pro rata reduction. The required reductions in the non-PX Scheduling Coordinators' Preferred Schedules will be based on a Scheduling Coordinator's forecast Generation (other than Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation) serving Direct Access End-Users.

If even further reductions in Generation are necessary, the ISO will proceed to step 3. In this step, every Scheduling Coordinator that has

454/ ISO Tariff, Section 2.3.4.4.4.

Eligible Regulatory Must-Run, Eligible Regulatory Must-Take or Reliability Must-Run Generation scheduled for the relevant hour will be required to reduce Generation. The Scheduling Coordinator's obligation will be proportional to the ratio of its scheduled amount of Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation to its aggregate Demand forecast for the relevant hour.

2. Real Time Overgeneration Protocol as described in the August 15th Filing

Before implementing Overgeneration procedures in the Real Time market, the ISO will identify any Scheduling Coordinator whose Generators are producing above their scheduled output and order that Scheduling Coordinator to reduce its output. If the Overgeneration condition remains, the ISO again proposes to follow a three-step procedure to resolve the Overgeneration condition. 455/

Step 1 requires the PX to reduce scheduled Generation. It is identical to the Day-Ahead procedure except that the PX also will use standing Conditional Demand Bids in price order in addition to reducing Generation other than Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation. Step 2 requires reductions in non-PX Generation. The reductions are applied to scheduled Generation (other than Eligible Regulatory Must-Run, Eligible Regulatory Must-Take and Reliability Must-Run Generation) serving Direct Access End Users in service areas of Eligible Regulatory Must-Run and Eligible Regulatory Must-Take Generation. The reductions in Real Time, however, are not determined on a pro rata basis. The ISO will require a reduction in the identified Generation on the basis of a predetermined order which will be rotated to ensure no undue discrimination. 456/ Step 3 is identical to the analogous step in the Day-Ahead Overgeneration procedure.

Contested Issues Identified by the ISO/PX

A large number of Parties object to Generation reductions under the Tariff because that procedure requires Scheduling Coordinators who have not contributed to the Overgeneration problem to take responsibility for resolving it. 457/ SMUD states that it would be consistent with current practice to require Overgeneration conditions to be mitigated by the Scheduling Coordinator experiencing the Overgeneration condition. 458/ Turlock states that the Tariff provision would result in cost shifting and that stakeholders

455/ ISO Tariff, August 15, 1997, Section 2.3.4.5.1.

456/ The process for determining the "predetermined order" is not specifi

457/ ISO/PX June 23, 1997 Reply Comments at 214.

458/ SMUD at 43.

prefer that the "bury you own dead" approach be adopted. This approach would require each Scheduling Coordinator to resolve any Overgeneration that results from its own schedule. 459/

June 23, 1997 ISO/PX Reply Comments

In its Reply Comments, the ISO/PX state that the ISO Governing Board agreed that the Overgeneration protocols were overly broad and thus amended the Tariff to apply the responsibility for reducing Generation to a particular set of Scheduling Coordinators, namely those with Eligible Regulatory Must-Run and Eligible Regulatory Must-Take Generation (the modifier Eligible was added) serving Direct Access End Users in service areas of Eligible Regulatory Must-Take or Eligible Regulatory Must-Run Generation. Since the Overgeneration procedures are designed to address the problem on a system-wide basis, the ISO Governing Board considered the "bury your own dead" approach alone to be too narrow.

September 2, 1997 Comments

CalEnergy contends that the revisions to the overgeneration provisions of the ISO Tariff endorsed by the ISO in the ISO/PX Reply Comments create ambiguities and that the Commission should endorse the specific clarifications proposed in CalEnergy's response. 460/ For example, CalEnergy states that it is not clear whether energy under contract to a UDC or Participating Transmission Owner is "owned or produced" by the UDC so that it can become Eligible Regulatory Must-Take Generation. The Tariff does not define the "Service Areas of Eligible Regulatory Must-Take Generation." It is not clear whether a Scheduling Coordinator may reduce Eligible Regulatory Must-Take Generation and Eligible Regulatory Must-Run Generation before all generation which is not must-run or must-take is reduced to zero. It is not clear whether a Scheduling Coordinator can reduce Eligible Regulatory Must-Take Generation as part of Step 2.

DWR states that the overgeneration protocols require further clarification regarding the scope of generation reduction. Although DWR supports the intent of the August 15 Filing (which is that during non-PX generation reduction, the protocols call for a reduction of the generation provided to the pre-restructuring end-users of the Companies, regardless of who now provides such generation), DWR believes that the provision is unclear. DWR recommends that the geographic focus on service areas is too broad and would include entities such as DWR that are located in these traditional service areas. DWR recommends modification of Sections 2.3.4.4.4 and 2.3.4.5.1 of the ISO Tariff to refer to Direct-Access End Users of the Investor Owned Utilities as of December 20, 1995.

459/ Turlock at 34.

460/ CalEnergy July 8, 1997 Comments at 2.

PG&E contends that the proposed revisions to ISO Tariff Section

2.3.4.5.1 do not require that the Scheduling Coordinator balance resources to match load, as intended. PG&E recommends that the provision be revised to state that the ISO will order any Scheduling Coordinator to reduce its Generation to balance load with Generation resources. 461/

BPA requests that the Commission direct the ISO to remove the definition of, and exception for, Eligible Regulatory Must-Take and Must-Run Generation from its overgeneration protocols. Also, BPA requests that the Commission direct the ISO to revise its overgeneration protocols to first reduce all PX generation to generation necessary for reliability and environmental benefits and then reduce all bilateral schedules on a pro rata basis. BPA argues that these sections have a discriminatory effect on out-of-state generators and provide a subsidy for California utilities because they require the reduction of all generation scheduled except for generation that is considered Eligible Regulatory Must-Take and Regulatory Must-Run Generation. BPA argues that its proposal would ensure that the scheduled generation of the Scheduling Coordinator responsible for the Overgeneration, e.g., the PX would be reduced first and that further reductions would be on a nondiscriminatory basis. 462/

DWR contends that each Scheduling Coordinator should be responsible for its own overgeneration problem by bearing the economic consequences of its own overgeneration. Specifically, the PX (and other Scheduling Coordinators) must take action to ensure appropriate load-resource balance in its schedule. If this is unsuccessful, then the PX would have to arrange with other Scheduling Coordinators to compensate for its overgeneration. The PX or other Scheduling Coordinator responsible for the overgeneration must provide compensation for costs incurred to reduce generation.

DWR contends that Section 2.3.4.5.1 is unclear which generating units will be allowed to stay on line despite overgeneration protocols. DWR and Metropolitan request deletion of ISO tariff section 2.4.2.2, which establishes priorities for Regulatory Must-Run and Regulatory Must-Take Generation absent overgeneration conditions. They state that the extent of the priority and the means by which the priority is provided are unclear. In addition, Metropolitan states that any priority given to such Generation during the Congestion Management would be unnecessary and inappropriate since it would ignore associated Adjustment Bids. Metropolitan also fears that such Generators could escape the Usage Charge obligation. 463/

Watson Cogeneration argues that the large volume of Regulatory Must-Take resources will result either in the frequent application of overgeneration protocols, or in a PX market that is very thin. Watson recommends that the Commission reject the proposal to curtail direct access supplies after PX volumes during overgeneration conditions under ISO Tariff Section 2.3.4.

461/ PG&E at 10.

462/ BPA at 84-86. See also, M-S-R at 13.

463/ Metropolitan at 37.

According to Watson, that preference violates the Commission's comparability standard and thins the PX market. Watson states that the PX needs to clarify how the PX price will be set during overgeneration conditions. 464/ In addition, Watson recommends that the California IOU s develop standardized QF contract modifications, available at the option of the QF, to allow QFs to bid

into the PX at their marginal cost of producing energy. 465/

Commission Response

The Commission will require that the problem of excess generation resulting from obligations associated with Regulatory Must-Run and Regulatory Must-Take Generation be resolved in a just and reasonable, and non-discriminatory manner. For reasons stated below, we find that Steps 2 and 3 of the Overgeneration procedures are not just and reasonable, or non-discriminatory. 466/ Accordingly, we will require the ISO to modify its treatment of Overgeneration as described below.

The Commission agrees with the position of DWR, SMUD, Turlock and others, that each Scheduling Coordinator should be responsible for its own Overgeneration problem by bearing the economic consequences of its own Overgeneration. In the words of Turlock, the Commission supports a bury your own dead approach to the Overgeneration problem. The ISO Tariff proposes to require that each Scheduling Coordinator s schedule be balanced, except in certain defined circumstances. One of those proposed exceptions is for a Scheduling Coordinator to submit unbalanced schedules to the ISO when its Regulatory Must-Run and Regulatory Must-Take generation is equal to or greater than its demand. 467/ We do not believe that Overgeneration should be a permissible exception to the balanced schedule requirement. We see no reason why one Scheduling Coordinator should be forced to serve its demand with the Must-Take Generation included in another Scheduling Coordinator s schedule. We direct the ISO to modify the ISO Tariff to require all Scheduling

464/ Watson notes that PX Tariff Section 3.9.2.4 provides for a minimum p during overgeneration conditions, pursuant to the Appendix B Auction Activity Rules; however, those rules do not discuss the minimum pric

465/ Watson at 1-7.

466/ Another problem with the Tariff is that although the definitions of Regulatory Must-Take and Regulatory Must-Run Generation were extende include a broader class of generators potentially owned by Schedulin Coordinators other than the PX, the definition of Overgeneration continues to apply exclusively to demand in the PX. According to th current definition, an Overgeneration condition could occur even whe the PX and all other Scheduling Coordinators have balanced schedules

467/ There are two other situations in which Scheduling Coordinators are allowed to have unbalanced schedules; in the proposed Intra-Zonal Congestion Management process and when Reliability Must-Run generati is scheduled.

Coordinators to individually resolve problems of excess generation due to their obligations with respect to Regulatory Must-Run and Regulatory Must-Take Generation according to their own procedures and submit balanced schedules to the ISO in the Day-Ahead market. 468/ We encourage Scheduling Coordinators to pursue trades to resolve the problem in the first instance. For Overgeneration in real time, Scheduling Coordinators will be required to resolve any excess generation problem by following their own internal procedures and as directed by the ISO. 469/

Further, the Commission agrees with Turlock, DWR, and Watson that allocating responsibility for resolving the Overgeneration to non-PX Scheduling Coordinators who do not contribute to the problem, as is done in steps 2 and 3, is unduly discriminatory, violates the Commission's comparability standard, and will cause cost shifting. In each of these steps, Scheduling Coordinators that do not contribute to the Overgeneration problem are nonetheless required to reduce generation.

We direct the ISO to remove the Overgeneration procedures from the ISO Tariff, since this is a problem that must be handled by Scheduling Coordinators. In addition, we direct the PX to develop procedures to resolve an Overgeneration problem within the PX and to modify the PX Tariff to include these procedures. To the extent that the PX is unable to develop new procedures or make modifications to software by the date that the PX begins operations, the PX should inform the Commission and request that these changes be staged.

The requests of CalEnergy and DWR for clarification of the Overgeneration protocols are moot given the ordered changes. Regarding Watson's suggestion on the development of standardized QF contract modifications, we encourage QFs and California electric utilities to negotiate mutually beneficial contract modifications that appropriately deal with excess generation and allow QFs to bid into the PX.

The Commission agrees with Watson that the PX needs to clarify how the PX price will be set during Overgeneration conditions. We understand that the PX will provide this clarification in the PX Protocols to be filed with the Commission on November 1, 1997.

V. PX Tariff

The PX states that it is a nonprofit corporation established for the primary purpose of providing an efficient, competitive Energy auction open on a non-discriminatory basis to all suppliers and purchasers, that meets the

468/ The balanced scheduling requirement would not apply to Intra-Zonal Congestion and Reliability Must-run Generation.

469/ The ISO will have the ultimate authority to direct Scheduling Coordinators to reduce generation to preserve reliability.

loads of exchange customers at market prices, and for other purposes. 470/ The PX would operate both a Day-Ahead and an Hour-Ahead 471/ bid-based Energy market, and would serve as the Scheduling Coordinator for PX participants. As a Scheduling Coordinator, the PX could elect to purchase Ancillary Services from the ISO or to self-provide some or all Ancillary Services.

A. Governance

Similar to the ISO, the proposed PX will be a not-for-profit, public benefit, corporation. Decision-making authority will be split between the PX Governing Board and the President and other officers of the PX. The PX Governing Board will oversee the establishment of the broad operating criteria

and protocols while the officers are responsible for day-to-day and real-time decisions of the PX. Article III of the PX Bylaws establishes the PX Board of Governors. 472/

The PX Governing Board will initially comprise twelve classes, each of which will elect directors that will represent the class on the board. The classes are: (1) Privately-owned Distribution Companies; (2) Publicly-owned Distribution Companies; (3) Public Buyers and Sellers; (4) Private Buyers and Sellers; (5) Non-utility Generators; (6) Agricultural End-users; (7) Industrial End-users; (8) Commercial End-users; (9) Residential End-users; (10) End-user At-Large; (11) Public Interest Groups; (12) Non-Market Participants. 473/ A majority vote is needed for approval of a PX Governing Board action. The directors will vote individually, not as a class. There will initially be a maximum of twenty-five members on the Governing Board. 474/

Privately-owned Distribution Companies

The Privately-owned Distribution Companies class will include any privately-owned distributor of Energy to end-users other than those companies previously exempted from regulation. The Privately-owned Distribution Companies class will have three governors. The Privately-owned Distribution Companies class will have a weighted voting procedure based on the kWh of Energy purchased through the PX.

470/ PX Tariff, Original Sheet No. 1, Introductory Statement.

471/ While the Tariff states that the PX will operate an Hour-Ahead marke the Staging Plan (at page 5) states that the PX will not begin opera an Hour-Ahead market until March 28, 1998.

472/ March 31 Filing, Vol. 1, Appendix 2.

473/ PX Appendix 2 to Volume I of the ISO/PX's March 31, 1997, Phase II filing at 9.

474/ Id. at 2.

Publicly-owned Distribution Companies

The Publicly-owned Distribution Companies class will include any municipality or municipal corporation, municipal utility district, public utility district or irrigation district, or any joint powers authority that includes one or more of these entities. The Publicly-owned Distribution Companies class will have three governors. For purposes of electing directors, the Publicly-owned Distribution Companies will have a weighted voting procedure based on the kWh of Energy purchased through the PX.

Public Buyers and Sellers Class

The Public Buyers and Sellers class will initially have two governors. Public entities that have purchased or sold Energy at wholesale from the PX at any time during the preceding twelve months are eligible to vote in any

election of a governor.

Private Buyers and Sellers Class

The Private Buyers and Sellers class is comprised of private entities, including power marketers certified by the Commission, that use the PX to buy or sell Energy. Utilities and their affiliates and municipal utilities or governmental entities and their affiliates shall not be eligible to participate in this class. Eligible entities will be those entities that have utilized the PX within the past twelve months for Energy-related purposes. The Private Buyers and Sellers class will have two seats on the ISO Governing Board.

Non-utility Generators Class

The Non-utility Generators class will include independent power producers, FERC-certified qualifying facilities, exempt wholesale generators, non-utility generators and similar entities. Utilities and their affiliates and municipal utilities or governmental entities and their affiliates shall not be eligible to participate in this class. Entities that have used the PX for Energy-related purposes during the past twelve months will be eligible to vote for the three governors that represent the class.

End-Users Classes

End-users will be represented on the ISO Governing Board by five classes: Agricultural End-users, Industrial End-Users, Commercial End-Users, Residential End-Users, and End-user At-Large. The Agricultural End-users class, the Industrial End-users class, and the Commercial End-Users Class will each have one seat on the PX Governing Board. The Residential End-users class will seat two governors and the End-User At Large class will have four governors.

Public Interest Groups and Non-Market Participants Class

Public Interest Groups and Non-Market Participants will each be a class and will be represented by two governors each on the PX Governing Board.

Contested Issues Identified by the ISO/PX

A number of parties raise generic issues related to the governance of both the ISO and PX. Our earlier discussion regarding issues related to the governance of the ISO summarized and addressed these issues.

Commission Response

We find the proposed governance structure to be consistent with our November 26, Order. As required in that Order: (1) no one voting class will be able to block or veto an action; (2) no two classes together will be able to form a sufficient majority to make decisions, and (3) no entity (including its affiliates and subsidiaries) will be able to participate in more than one

voting class. 475/

We also accept the PX's proposal to submit to the Commission, no later than three years after adoption of the PX Bylaws, a recommendation as to whether the proposed class structure requires modification. We note that this commitment in no way precludes any person from filing a complaint under section 206, or the Commission on its own motion instituting an investigation under section 206, regarding the governance structure.

However, consistent with our findings discussed earlier in this order, we deny requests for reconsideration of our prior determination rejecting: 1) the California residency requirement contained in Article II, Section 3 of the PX Bylaws; and 2) the ongoing role of the Oversight Board as reflected in various provisions of the PX Bylaws. 476/

B. PX Eligibility Requirements

Section 2.2(e) of the PX Tariff requires entities that own or control transmission capacity outside of the ISO Controlled Grid to provide reciprocal transmission service to other PX Participants. Specifically, Section 2.2(e) of the PX Tariff states that:

475/ November 26 Order, 77 FERC at 61,816-61,817.

476/ See, e.g., Article II, Sections 3, 3(f)(ii), 3(g)(ii), 3(h)(ii), 3(i)(ii), 3(j), 3(k)(iii), 3(l)(ii), Section 4(a), 4(c), Section 6, Section 7, Section 13, Article VII, Section 3(a) and 3(b), as set fo in the March 31 Filing, Volume 1, Appendix 2.

> If it owns or controls transmission capacity outside the ISO Controlled Grid, FERC has determined that an open access transmission tariff for the entity conforms to the substantive requirements of Order No. 888, including comparable transmission pricing.

With respect to non-jurisdictional entities, this section means that a non-public utility will satisfy the eligibility requirements of Section 2.2(e) if the Commission grants a petition that its transmission tariff meets the Order No. 888 requirements.

Comments

Numerous parties complained that this provision is an inappropriate barrier to participation in the PX. Parties argue that Section 2.2(e) conditions the purchase or sale of Energy or Ancillary Services using the PX on the requirement to provide reciprocal non-discriminatory transmission service. Parties state that this requirement goes beyond the reciprocity requirements of Order No. 888. In addition, parties contend that this provision is inconsistent with the voluntary provisions of Order No. 888 in that it requires the filing on an open-access transmission tariff with the Commission. In Order No. 888 the Commission stated that parties could voluntarily submit a transmission tariff under the "safe harbor" procedures or

file a transmission tariff with the administrator of an RTG. 477/ The ISO/PX filed reply comments on September 16, 1997, stating that they agreed with the parties and that the provision inappropriately ties the provision of Energy services to the offering of transmission service. 478/

Commission Response

We conclude that Section 2.2(e) of the PX Tariff inappropriately ties the provision of Energy-related services and open-access transmission service. Therefore, we direct the PX to delete Section 2.2(e) from the PX Tariff.

C. The PX Auctions

Description of the Proposal 479/

477/ See, e.g., August 29, 1997, Motions for Clarification, or in the Alternative, Requests for Rehearing of CMUA at 3-7; Turlock at 10-11 Modesto at 20-24; M-S-R at 18-24; TANC at 20-24; Metropolitan at 18- and SMUD at 7-9.

478/ ISO/PX September 16 Comments at 15.

479/ This section describes the PX auction proposal as described in the P (continued...)

Overview of the PX Day-Ahead Energy Market

In the Day-Ahead market, the PX would accept bids from suppliers and purchasers of Energy. Based on these bids, the PX would develop supply and demand curves (using Protocols that the ISO/PX have indicated will be filed by November 1, 1997) and calculate the resulting tentative Market Clearing Prices and quantities and develop a Preferred Schedule. In developing the Preferred Schedule, the PX would not consider transmission congestion, and the Market Clearing Price in any hour would be the same in all locations. However, prices in different hours may vary. The PX would forward the Preferred Schedule to the ISO. The PX would also assess the potential for Overgeneration and communicate any Overgeneration conditions to the ISO and PX participants. 480/ Overgeneration would occur whenever the aggregate amount of Energy available to be generated in any hour by Regulatory Must-Take, Regulatory Must-Run, and Reliability Must-Run Generation resources exceeds the amount of Energy demanded by participants in the PX.

The PX would also accept Adjustment Bids from any PX participants that voluntarily submit them, and forward them to the ISO for use in Congestion Management. Adjustment Bids state how much a bidder is willing to increase or decrease its Energy supply or demand at various prices.

After the ISO receives Preferred Energy Schedules from all Scheduling Coordinators, it would determine whether transmission congestion would result from the schedules. If not, then all Preferred Schedules, including the PX Preferred Schedule, would be accepted and become Final Schedules. In this case, the PX's tentative Market Clearing Prices underlying the Preferred Schedule would become final. 481/

However, if the ISO determines that the Preferred Schedules would be infeasible in the aggregate because of transmission congestion, the ISO would use the Adjustment Bids voluntarily submitted to it to develop suggested adjusted schedules for Scheduling Coordinators and advisory Usage Charges for transmission. 482/ In response, the PX would have two (and ultimately three) options. Initially, it could (1) accept the ISO's suggested adjusted schedule, or (2) resubmit its original Preferred Schedule. In the future, after giving 30 days prior notice on WEnet, the PX could also choose a third alternative: developing its own revised schedule.

479/ (...continued)
Tariff and the Staging Plan. As noted below, certain portions of th Tariff are inconsistent with the Staging Plan.

480/ PX Tariff, Sections 3.3.4 and 3.3.5

481/ PX Tariff, Section 3.9.2.6

482/ The ISO's Congestion Management process is described more fully in Section IV. A. of this order.

Other Scheduling Coordinators may also submit revised schedules. If the schedules submitted to the ISO fully resolve congestion, they would be accepted and become final. If congestion is not resolved, the ISO would determine Final Schedules that resolve congestion and establish Usage Charges for any congested interzonal interfaces, based on the Adjustment Bids that it received.

In instances where Final Schedules involve interzonal congestion, the ISO rejects the PX's initial Preferred Schedule, and the ISO assesses a transmission Usage Charge, the PX would establish different Energy prices in different active zones. In these instances, the PX would establish the applicable Energy prices based on PX Protocols to be filed with the Commission. However, the ISO/PX's August 15 response to a FERC Staff Data Request provided an example of how the PX would establish zonal market-clearing Energy prices during periods of interzonal congestion. 483/ In brief, the market-clearing price in any one zone underlying the Final Schedule would equal the marginal cost of producing and delivering Energy to the zone. The marginal cost of producing Energy would be determined based on the Adjustment Bids submitted by PX participants. The resulting prices in different active zones would differ by the amount of the applicable Usage Charge.

The PX would obtain revenue to pay for the ISO's Usage Charges from its operation of the Energy market. Specifically, the PX will generally collect more revenue in total from Energy buyers (who would purchase proportionately more Energy in the higher-priced zone) than it pays to Energy sellers (who would sell proportionately more Energy in the lower-priced zone). The difference would be used to pay the ISO's Usage Charges. 484/ However, to the extent that the PX's revenue collection differs from the Usage Charges owed to the ISO, the PX would collect or rebate the difference, as applicable, to or from all PX participants. 485/

Details of the Proposed Market-Clearing Price Determination Process

As described above, the PX would use the bids received in the Energy auction to construct supply and demand curves and calculate market-clearing prices. Section 3.9.2 of the PX Tariff describes the details of the PX's Market Clearing Price determination. If the supply and demand curves intersect at a single point, the point of intersection would establish the Market Clearing Price and quantity. If there is no point of intersection or more than one point of intersection, the Market Clearing Price will be determined in accordance with PX Protocols. Tied bids would be resolved in

483/ August 15 Filing, Appendix III, Response to Question 9, pp. 11-12 an Attachment 6.

484/ PX Tariff, Section 6.2.3

485/ PX Tariff, Sections 6.2.3, 3.9.2.6, and 3.9.2.7.

accordance with the PX Auction Activity Rules, to be filed with the Commission.

When Overgeneration exists and the marginal demand bid price equals the minimum prices under the Activity Rules, the Market Clearing Price would be that minimum price. When there isn't enough supply to meet demand, the Market Clearing Price would be the lower of the maximum price specified under Section 3.8.1.2 or the price determined in accordance with PX Protocols.

The specific auction format governing how the PX's auction would be conducted has evolved significantly over time. The Phase I filing proposed an auction for the day-ahead market, which differs from the Day-Ahead auction now being proposed, while the Phase I proposal for the Hour-Ahead auction has not changed. 486/

Under the Day-Ahead auction proposed in the March 31 Phase II filing and the August 15 filing, suppliers (and buyers) would submit a set of Energy bids for each of the 24 hours in the day. 487/ Bids would not be submitted for start-up or no-load, and no information would be provided regarding ramp rates or other technical information. Also, each day's auction would take place over several rounds, or iterations. In each round, participants would submit Energy bids indicating how much Energy they would be willing to sell or buy in each hour at various prices. 488/ Based on these bids, the PX would announce tentative Market Clearing Prices for each hour and a tentative schedule of quantities for each participant. In any round, participants could change their bids from the previous round, subject to certain Activity Rules (which the ISO/PX intends to file for informational purposes at a later date 489/). The rounds of bidding would continue until either no bids changed or time ran

486/ Joint Application of Pacific Gas and Electric Company, San Diego Gas Electric Company, and Southern California Edison Company for Authori to Sell Electric Energy at Market-Based Rates using a Power Exchange April 29, 1996, (Phase I PX Filing), pp. 40-52.

487/ See, PX Tariff, Section 3.8.1.1 Form of Bids. A PX Participant may specify up to sixteen quantity price points for each hour, as long a

these points, taken in order, define a curve that includes no more t ten non-vertical line segments. The prices shall be increasing with quantity for suppliers and decreasing with quantity for demanders.

488/ Under Section 3.3.2 of the PX Tariff, a bid need not initially be attributed to any particular demand, generating unit or system resou Such bids are referred to as portfolio bids. However, if any part a portfolio bid is accepted into the PX's initial Preferred Schedule the bidder must then convert the bid into a schedule that attributes specific quantities to specific demands, generating units and system resources before the PX submits its Preferred Schedule to the ISO.

489/ An example of the Activity Rules that the PX may apply is found in Appendix B of the PX Tariff, but the Tariff does not commit to using rules in the example.

out. 490/ The ISO Scheduling Process described in the ISO Tariff Appendix C indicates that the PX auction would allow up to five rounds of bidding per day. However, the Staging Plan submitted on August 15 indicates that initially only one bidding round would be permitted, and that multiple bidding rounds would not be introduced until June 27, 1998. 491/

In addition to the Day-Ahead Energy market, the PX proposes to operate an Hour-Ahead Energy market. (The Staging Plan states that the Hour-Ahead market would not be implemented until March 28, 1998, although the Tariff makes no mention of the delayed starting date.) In the Hour-Ahead auction, participants would submit bids only for Energy and not for start-up or no-load. Thus, the Hour-Ahead market would operate in a fashion similar to the Day-Ahead market. The main difference is that, under the Hour-Ahead auction format, only one round of bidding would be permitted in the hour-ahead auction. (By contrast, the Day-Ahead auction would permit multiple rounds of bidding, as of June 27, 1998.)

Overview of the Ancillary Service Auction

Under the Phase II proposal, the PX may elect either to purchase Ancillary Services from the ISO, or partly or completely self-provide Ancillary Services. If the PX elects to self-provide any Ancillary Services, it would conduct an Ancillary Services auction using equivalent rules to those used by the ISO. The proposed PX Ancillary Services auction would be carried out sequentially after closing the Energy auction. 492/ The Staging Plan indicates that the PX intends to begin to self-provide Ancillary Services during the second half of 1998. 493/

Settlements and Billing

The PX would settle with each PX Participant for Energy and Ancillary Services traded in the Day-Ahead Market in each settlement period based on the Participant's commitment as specified in the final Day-Ahead Schedule and the applicable Day-Ahead Market Clearing Price. 494/ To the extent that a PX Participant's quantities of Energy or Ancillary Services specified in the Hour-Ahead Schedule differ from those in the Day-Ahead Schedule, those differences would be settled at the applicable Hour-Ahead Market Clearing

490/ PX Tariff, Sections 3.3.4 and 3.3.5.

491/ Staging Plan, p. 5

492/ PX Tariff, Sections 3.10 and 3.10.1

493/ Staging Plan, p. 5

494/ PX Tariff, Section 6.2

Price. 495/ Any deviation in Energy traded in real time from the amount scheduled in the Day-Ahead Market as adjusted by the schedule in the Hour-Ahead Market would be settled at the applicable Hourly Ex Post Price. 496/ Under Section 6.2.4, the PX may file with the Commission to impose additional rules to be applied against any PX Participant whose liability for Imbalance Energy (created by trading more Energy in real time than is scheduled in the Day-Ahead and Hour-Ahead Markets) is determined by the PX to be excessive. Specifically, the PX may seek to impose restrictions on the Participant's right to bid in any PX Market or increase the Participant's security amount. According to the Tariff, the rules would be sought to discourage such Participants from enjoying the use of interest free money associated with settling positions in the forward markets in advance of settling purchases of Imbalance Energy.

Contested Issues Identified by the ISO/PX

The California Commission contends that PX Tariff Section 3.9.3 should be eliminated as inappropriate. Section 3.9.3 of the PX Tariff states: The PX will implement mechanisms to encourage bids and facilitate offering or seeking demand side bids for Energy Efficiency Services. The California Commission argues that this provision should be deleted because it would require the PX inappropriately to bias the Energy auction in favor of demand side bids for such services. In the California Commission's view, it is not appropriate for an independent PX to "be in any way involved in determining the results of a competitive market." 497/

TURN/UCAN proposes that the PX allow its traders to submit separate Adjustment Bids for congestion management that are different from their bids submitted to the PX for its Energy auction. 498/ According to TURN/UCAN, the use of different Adjustment Bids would allow PX traders to modify their position in the PX Energy auction at the close of Congestion Management.

LADWP contends that the auctions for Energy and Ancillary Services should be conducted simultaneously rather than sequentially. The PX Tariff currently provides that the evaluation of Ancillary Service bids by the PX shall be carried out sequentially after the Energy auction has closed. 499/ According to LADWP, the PX should evaluate bids for the total quantity of capacity required on-line for Energy plus on-line Ancillary Service requirements. The PX would determine which blocks of capacity are to be scheduled for Energy and which are to be scheduled for Spinning Reserve and

495/ PX Tariff, Section 6.3

496/ PX Tariff, Section 6.4

497/ California Commission at 96-97.

498/ TURN/UCAN at 111.

499/ PX Tariff □ 3.10.1

AGC. The PX would then select the units with the highest decremental bid prices which have a non-zero capacity available to provide Spinning Reserve and AGC until its requirements have been met. LADWP argues that this approach would be more efficient and easier to implement since Energy and Spinning Reserve are joint electrical products. It should also lower total cost for Energy and Spinning Reserve through reduced unit commitment. 500/

The California Commission contends that the proposed bidding Tariff Provisions and Activity Rules provide a foundation for a sound bidding procedure. 501/ However, the California Commission, Southern California Edison, and others express concern that the PX has not filed the final Activity Rules that will govern the PX auction. These parties state that the PX should be required to file its final Activity Rules prior to final FERC approval. 502/

TURN/UCAN recommends that the auction should initially have only a single round and allow only day-ahead and real-time markets. Later, additional bidding rounds could be added along with hour-ahead markets. 503/ The ISO/PX's August 15 Staging Plan include these recommendations.

TURN/UCAN contends that additional work is needed to consider the effect of transmission constraints on the auction. PX traders must predict congestion prices before bidding, and PX generators must construct a composite price for Energy, Ancillary Services, and congestion management to determine if they will be competitive and should generate in the presence of congestion. 504/

The California Energy Commission (CEC) argues that the Phase II PX auction, in conjunction with the ISO's Congestion Management procedures, is operationally complex and raises questions about whether it will unduly sacrifice efficiency, especially when Congestion requires additional adjustments to the PX Preferred Schedule. 505/

June 23, 1997 ISO/PX Reply Comments

500/ LADWP at 16.

501/ California Commission comments at 15.

502/ See, e.g., California Commission comments at 91; and August 29, 1997 Request for Rehearing by Southern California Edison, at 3-4.

503/ UCAN/TURN comments at 6. In Edison's view, the Activity Rules will a significant effect on Energy rates.

504/ UCAN/TURN comments at 6.

505/ CEC comments at 21.

In response to the California Commission, the ISO/PX respond that Section 3.9.3 of the PX Tariff obligates the PX Governing Board to review the PX bidding operating procedures in order to ensure that environmentally sensitive demand side bids will be facilitated and given as fair a treatment as any other bids in the market where feasible. 506/ According to the ISO/PX, the main target for the PX Governing Board will be to ensure that the rules and operating procedures work for all and work properly. As to the argument of excessively burdening the PX, the ISO/PX do not anticipate that there will be a substantial cost burden to the PX and, if there is, expect the PX Governing Board will take the fact strongly into account in deciding the issue of feasibility. Thus, the ISO/PX contend the provision is intended to be helpful and should remain.

In response to TURN/UCAN's proposal to allow adjustment bids that differ from PX Energy bids, the ISO/PX respond that this proposal, if adopted, would undermine the efficacy of the entire iterative PX Energy auction. 507/ The convergence of the auction mechanism is dependent on the closure leading to a binding contract to generate or purchase power at the clearing price in the hour. The ISO/PX argue that by allowing traders to change their bids in a final round after congestion management, a host of "end game" effects can be anticipated, i.e., only the final bids will reflect true offers to buy or sell. Under these circumstances traders are under little pressure to bid down towards their costs as the auction moves towards closure, since all bids can be adjusted later. The ISO/PX also argue that implementation of the TURN/UCAN proposal would also require further complexity in the software links between the PX and ISO systems. Timely implementation of the market structure is dependent on minimizing interactions between the required systems and software.

The ISO/PX argue that the issues raised by LADWP's proposal are similar to issues raised concerning the relationship between the PX Energy auction and the ISO Ancillary Services auction. The ISO/PX state that after extensive discussion and consultation, it was decided that the market design for California should be based upon sequential markets for Energy and Ancillary Services. 508/

According to the ISO/PX, there are a number of reasons for this being the preferred approach in the PX Markets as well. First, it is not practical for the two markets to be conducted simultaneously. The demand for Ancillary Services will not be fully known until the Energy market is closed. Second, simultaneous markets for Energy and Spinning Reserve would only add unduly to the complexity of the process. There are other Ancillary Services which are subject to the PX auction. Third, concerns about the efficiency of separate and sequential markets for Energy and Ancillary Services are not justified. The ISO/PX argue that daily repetition of the day-ahead Energy and Ancillary

506/ ISO/PX June 23, 1997 Reply Comments at 286.

507/ ISO/PX June 23, 1997 Reply Comments at 359.

508/ ISO/PX June 23, 1997 Reply Comments at 202 and 359.

Service markets will allow bidders to estimate the likely results of each auction, and any errors in estimating the results of the day-ahead market can be largely offset by bidding in the hour-ahead markets.

September 2, 1997 Comments

Although the California Commission supports the staged implementation of PX operations as reasonable and prudent, it states that the PX must address the implications of having only one round of bids. 509/ The California Commission also recommends closer scrutiny for exercises of market power while there is only one round of bidding. Therefore, the California Commission recommends review of the proposed Staging Process.

Although the references to iterative bidding were removed from the PX Tariff, the California Commission notes that the PX Tariff fails to indicate clearly that iterative bidding in the Day-Ahead market will be staged. The California Commission reserves the right to file comments on the PX bidding and bid evaluation protocols once they are filed. 510/

SoCal Edison contends that the August 15 revision to section 3.9.2.2 of the PX Tariff, which now provides for the initial Market Clearing Price to become final when there is no Inter-zonal Congestion, will result in an inefficient and inequitable increase in the price of Energy in the PX when Reliability Must-Run generation is constrained on. 511/ SoCal Edison points out that at times when the ISO schedules Reliability Must-Run generation after the initial PX Preferred Schedule has been submitted, some competitive demand will be removed from the PX market. SoCal Edison argues that this must be taken into account in determining the PX s Market Clearing Price, or the PX Energy price will be overstated. However, according to SoCal Edison, there is no mechanism to adjust the Market Clearing Price in that situation. 512/ Because there could be significant amounts of Reliability Must-Run generation during some hours, SoCal Edison considers this problem to be substantial, and

509/ For example, if the PX schedule is not feasible by the ISO after the PX submits its balanced schedule to the ISO, the California Commission asks whether the ISO or PX would ensure feasibility. Also, if the PX schedule needs to be readjusted, how would the accounts of the PX participants be settled, asks the California Commission (Id. at 36).

510/ California Commission at 37.

511/ SoCal Edison at 4-6.

512/ For example, SoCal Edison explains, if PX demand is 10,000 MW and the Market Clearing Price is $25/MWh, and the ISO orders 2,000 MW PX generation to be backed down so that 2,000 of Reliability Must-Run generation can be scheduled, the Market Clearing Price should be red to the bid of the marginal unit at 8,000 MW.

requests the problem be remedied prior to the requested January 1, 1998 start-up date, regardless of software limitations.

The California Commission comments that the PX has not adequately explained how it is possible for the PX to over-collect its revenues based on the example the PX provided in response to the Commission s July 18, 1997 Request for Information. Also, the California Commission is very concerned with the PX s suggestion that it may simply adjust the zone adjustment bid marginal cost based prices after the fact, where there is an underrecovery of Usage Charge revenues. According to the California Commission, such after-the-fact adjustments undermine the adjustment bid process and should not be permitted. 513/

Commission Response

Bid Structure

Section 3.9.3 reads:

> The PX will implement mechanisms to encourage bids and facilitate offering or seeking demand side bids for Energy Efficiency Services.

The California Commission is concerned that Section 3.9.3 actively determines the result of the competitive market by preferentially favoring demand side bids for Energy Efficiency Services. The ISO/PX has clarified, in response, that Section 3.9.3 merely ensures that the market does not discriminate against the demand side bids. To ensure that the prices in the PX Energy Market are just and reasonable and not unduly discriminatory, as required by section 205 of the FPA, we must be sure that all participants are treated in a nondiscriminatory fashion, and that no participant is given undue preference. On the basis of the ISO/PX interpretation, we will accept Section 3.9.3.

PX Energy Bids and Adjustment Bids

TURN/UCAN raises the issue of whether a PX Participant should be allowed to submit Adjustment Bids for use in congestion management that differ from the bids it submits to the PX during the Energy auction. The ISO/PX in its June 23 Reply Comments and in its August 15 description of contested issues contends that the bids should not differ. The reason given is that allowing different bids would allow bidders to circumvent the auction Activity Rules and undermine the efficacy of the iterative PX Energy auction. However, the ISO/PX offers a different view -- namely, that the bids can be different -- in their August 15 Data Responses to Staff requests for additional information.

513/ California Commission at 40. The PX example discussed by the California Commission is in the August 15 Filing, Appendix III, Response to Question 9 (at 9-10) and Attachment 6 (at 127-132).

514/ Since the ISO/PX has given two contradictory responses to this issue, it is not clear the extent to which the ISO/PX and TURN/UCAN are in disagreement.

However, we would observe that it is difficult to distinguish failure to submit an Adjustment Bid (which is permitted under the Phase II filing) from submitting an Adjustment Bid that is different from the Energy Bid. The ISO/PX argue in their Reply Comments that allowing the bids to differ would allow bidders to circumvent the auction Activity Rules. We cannot fully evaluate this assertion because the final Activity Rules have not been filed with us; we have only example Activity Rules for illustrative purposes. We will defer a decision on this issue until the PX files its Activity Rules and we are able to review them. At that time, we will determine to what extent the Energy Auction Activity Rules should govern Adjustment Bids of PX Participants.

PX Ancillary Services Auction

LADWP raises the issue of whether the PX auctions for Energy and Ancillary Services should be sequential or simultaneous. The ISO/PX proposal is for sequential auctions. LADWP favors a simultaneous auction. In our December 18 Order, we suggested that there may be economic benefits to considering Energy and Ancillary Services simultaneously, and required the ISO/PX to discuss the issue further in the Phase II filing. 515/ In particular, our concern was that a sequential auction may create more risk for bidders than a simultaneous auction. If so, the additional risk may inefficiently increase the costs of providing Energy and Ancillary Services and/or discourage some low-cost generators from providing services. As a result, the additional risk may raise the prices of these services to consumers.

As noted above, the ISO/PX responds that the risk of incorrect estimates is minimal in large part because the auctions will be repeated daily, allowing bidders to accurately estimate future auction results based on past outcomes. Moreover, inaccurate estimates of the day-ahead markets can be at least partially offset by bidding in the hour-ahead markets.

Whether sequential or simultaneous auctions are more efficient is an unresolved empirical question. Accordingly, we will approve the proposal for sequential auctions on an interim basis in order to gather experience with which to evaluate the proposal more fully at a later date. To assist us in that evaluation and to address the concerns articulated above, we will require the PX to conduct further studies, and to file a report on their results by January 1, 1999, at which time we may revisit the issue. The studies should

514/ Submittals of the California ISO and PX, Appendix III, August 15, 19 p 16, response to Question 23.

515/ 77 FERC at 62,094 - 62,096.

analyze and compare sequential and simultaneous auctions in terms of their abilities to develop an efficient, least-cost dispatch.

Inconsistencies between the PX Tariff and the Staging Plan

In several places, the PX Tariff and the Staging Plan are inconsistent with each other. For example, Section 3.1 of the PX Tariff states (among other things) that the PX shall operate an Hour-Ahead Energy Market and shall calculate prices for and settle trades in that market. The ISO/PX has requested to put the PX Tariff into effect on January 1, 1998. However, the Staging Plan states that the PX shall not operate an Hour-Ahead Energy Market until March 28, 1998. 516/ Consistent with the discussion of Staging earlier in this order, if the PX does not intend to operate an Hour-Ahead Energy Market on the date when it begins operations, it must revise its Tariff posted on the WENet accordingly. The PX may request permission to begin operation of an Hour-Ahead Market by filing the necessary revised Tariff Sheets 60 days before it is prepared to begin operation.

The PX Tariff also states (for example, in Section 3.3.4) that PX Participants may revise their bids in successive iterations during each daily Energy auction. However, the Staging Plan states that only one round of bidding will be permitted initially, and that multiple bidding rounds will be permitted only as of June 27, 1998. 517/ If the PX does not intend to permit multiple bidding rounds when PX operations commence, Section 3.3.4 (and other applicable Sections) of the PX Tariff must be revised accordingly. The PX is directed to make the necessary revisions to the PX Tariff. The PX may request permission to permit multiple bidding rounds in the Day-Ahead Energy auction by filing the necessary revised Tariff Sheets 60 days before it is prepared to permit multiple bidding rounds.

The PX Tariff states in Section 3.10 that the PX may choose whether to partially or completely self-provide Ancillary Services. Any self-provided Ancillary Services would be obtained through an auction using rules equivalent to those used by the ISO. The Staging Plan states that the PX will not begin holding Ancillary Service auctions until the second half of 1998. If the PX does not intend to hold Ancillary Services auctions when PX operations commence, Section 3.10 (and its subsidiary sections, 3.10 and 3.10.2) must be revised to delete references to PX self-provision of Ancillary Services and the PX Ancillary Services auction. The PX may request permission to hold an Ancillary Services auction to acquire self-provided Ancillary Services by filing under section 205 60 days before it is prepared to hold an Ancillary Services auction.

516/ Staging Plan, p. 5

517/ Staging Plan, p. 5

Activity Rules and Other Protocols

In our July 30 Order, we approved the ISO/PX proposal that documents labeled as protocols may be filed on November 1 for informational purposes on the grounds that they merely described implementation details and not matters that had a significant effect on rates. 518/ Southern California Edison and others seek rehearing on this issue. They contend that many

documents labeled as protocols, such as the auction Activity Rules, do indeed have a significant effect on Energy rates, and thus should be formally filed with the Commission and subject to our approval before they take effect.

We conclude that the Activity Rules for the PX auction must be filed under Section 205. Interested parties will be given an opportunity to comment on the proposed Activity Rules at that time. As noted earlier in this order, the Commission will review the other protocols that are submitted by November 1 and will assess at that time whether any of these protocols must also be filed under Section 205 and included in the PX or ISO Tariffs.

The Activity Rules appear to have a significant effect on Energy rates. We cannot determine whether the PX auction process will result in just and reasonable Energy rates without knowing the rules that will govern the auction process. Submitting the Activity Rules merely for informational purposes is insufficient for us to carry out our responsibilities under the Federal Power Act.

Auction Format

The PX, when it commences operations, will operate the largest market for electric energy in California. The three California IOUs will buy and sell all of their Energy through the PX for the first several years. The PX's auction format will be a key determinant of the level of PX Energy prices. It is therefore a vital goal that the PX auction format promote an efficient dispatch and prices. The auction format used by the PX could have a significant effect on the PX's dispatch and prices.

As noted above, the California Energy Commission (CEC) expresses concern that the Phase II auction format is operationally complex and raises questions about whether it will unduly sacrifice efficiency. Other commenters expressed support for the concept of the Phase II auction format. TURN/UCAN, while supporting the concept of an auction format that uses only one-part Energy bids, nevertheless contends that additional work is needed to consider the effect of transmission constraints on the auction.

In response, we observe that the Phase II auction would require generators to decide unit commitment for themselves. That is, by submitting an Energy bid less than the final applicable Market Clearing Price in an hour, a unit would be automatically scheduled and committed, regardless of whether

518/ 80 FERC at 61,423.

it could ultimately cover its start-up and no-load costs. Of course, when they submit their bids, generators can only estimate what Market Clearing Prices are going to be in for the upcoming day. Hence, they would face uncertainty regarding whether the day s prices will be high enough to cover their start-up and no-load costs, and thus, whether they should commit their units for the day. To address this uncertainty, the March 31 Phase II filing proposed that the day-ahead auction permit several rounds of bidding. Multiple bidding rounds could provide price discovery and allow individual generators to withdraw if prices appeared inadequate to cover their start-up and no-load costs.

The ISO/PX argues that the Phase II auction would be transparent and

easy to understand. The ISO/PX contends that participants could easily verify the process by which Market Clearing Prices and Preferred Schedules are decided in the Phase II auction. Moreover, in the ISO/PX s view, the use of multiple bidding rounds, combined with the auction s Activity Rules would provide bidders with sufficient information to make efficient unit commitment decisions. 519/

However, as noted above, the Staging Plan states that initially only one round of bidding would be used in the auction, and that additional rounds of bidding would not be permitted until June 27, 1998. Moreover, the ISO/PX have not yet submitted the Activity Rules that will govern the bidding process. The ISO/PX state that they intend to file the initial Activity Rules for informational purposes by November 1, 1997.

We have concerns about the Phase II auction, which are discussed in more detail below. We nevertheless believe the proposal is sufficient to implement on an interim basis so that the participants can learn how the auction will work under real market conditions. We will accept on an interim basis the proposed Energy auction format described in the August 15 filing. After experience and further studies that we will require, the PX will be in a better position to propose any modifications necessary to assure that the auction mechanism continues to produce prices that are just and reasonable, and promote an efficient and competitive electricity market free of undue discrimination and preference.

The Commission believes additional studies should be conducted to determine whether the Phase II auction will, in practice, promote an efficient dispatch. We are concerned in particular about whether the proposed Phase II auction format will permit participants to make efficient unit commitment decisions that will result in the lowest reasonable prices to consumers, especially since the auction contemplates at most only a few rounds of bidding per day. (Initially, the auction would have only one round of bidding. Later, the auction could have up to five rounds.)

519/ August 15 Filing, Appendix III, Attachment 1, Report to the Californ Trust for Power Industry Restructuring, Activity Rules for the Powe Exchange, by Robert Wilson.

The ISO/PX submitted studies by Professor Charles Plott and London Economics to support their auction format proposal in Phase II. These studies are a first step in evaluating the auction proposals, since there is little or no real world experience for evaluating the proposals. Moreover, these analytical methods could allow analysts to compare the effects of using different auction formats while holding constant the effects of other variables that may also affect results, such as the costs of market participants and the level of market concentration. The techniques could also allow analysts to compare the efficiencies of alternative auction formats with each other and with an efficient, least-cost dispatch.

We will require that the PX conduct additional studies to further evaluate the proposed auction, which must be completed and submitted to us by January 1, 1999. The studies should analyze whether the Phase II auction results in an efficient, least-cost dispatch. The effect of limiting the number of iterations in the Phase II auction (so that the auction may

terminate before reaching an equilibrium) should be explored, since the ISO/PX proposes only one round of bidding initially, and only five rounds of bidding later on. Also, the effects of transmission congestion and the existence of no-load costs on the part of generators should be explored for each auction.

The studies should also examine the effects of the regular repetition of auctions involving the same participants and similar costs from day to day. The studies should pay specific attention to the susceptability of the auction format to overt and tacit collusion and the potential to exercise market power.

Imbalance Energy

Under Section 6.24 of the PX Tariff, the PX would seek (through appropriate filings with the Commission) to impose additional rules to penalize excessive liability for Imbalance Energy. The PX's concern is the ability of PX Participants with excessive imbalances to enjoy interest free money, due to timing differences in settling forward market and imbalance Energy market positions. In response, we note that the PX, as a FERC-jurisdictional entity, has a statutory right to file for changes in its rates, terms, and conditions of service. We will review any proposals for additional rules relating to liabilities for Imbalance Energy if and when they are filed with us. We note, however, that the PX has a responsibility to complete its settlements in a timely manner and should minimize any delays between forward market and imbalance market settlements.

Section 3.9.2.2

SoCal Edison recommends revising Section 3.9.2.2 to allow the PX to reduce its Market Clearing Price in certain instances when no Inter-zonal Congestion is present. Specifically, SoCal Edison would allow the PX to reduce the Market Clearing Price when the ISO orders reductions in PX generation in the PX Preferred Schedule to offset production from Reliability Must-Run Generation. We will deny SoCal Edison's request.

The ISO will call a Must-Run generator when needed (1) to supply Energy to meet demand within a load pocket or (2) to provide voltage support. We will address SoCal Edison's comment from the perspective of these two uses of Must-Run generation. When the Must-Run generator is called to produce Energy, the load pocket (which creates the need for the Must-Run Energy) would develop because a transmission constraint (often within a zone) prevents sufficient generation from outside the pocket from being delivered to meet demand in the pocket. The situation raised by SoCal Edison is one example of a more general situation that may occur when resolving Intra-Zonal Congestion. We are not persuaded to provide different treatment when Must-Run Generation is involved than in other instances of Intra-Zonal Congestion.

That is, when Intra-Zonal Congestion exists, a transmission constraint within a zone requires an adjustment to at least some Preferred Schedules in order to meet demand. To alleviate the constraint, the ISO would order additional Energy to be generated (in some instances from Reliability Must-Run Generators) on the import side of the constraint. The ISO would also order a corresponding reduction in some generation on the export side of the constraint. As a result, the marginal cost of Energy will differ on the two sides of the constraint.

The Market Clearing Price underlying the PX's Preferred Schedule is developed under the assumption of no congestion. However, when Intra-Zonal Congestion exists, the price underlying the PX's Preferred Schedule is likely to exceed the real marginal Energy cost on the export side of the constraint. The PX price is likely to be lower than the real marginal Energy cost on the import side of the constraint. SoCal Edison argues that when Reliability Must-Run Generation on the import side displaces PX generation on the export side, the PX Market Clearing Price to be applied to the entire zone should be reduced. SoCal Edison contends that Section 3.9.2.2's failure to allow the price reduction is inefficient and inequitable.

SoCal Edison is only partly correct. While the marginal Energy cost on the export side of the constraint is likely to be lower than the price underlying the unadjusted Preferred Schedule, the marginal Energy cost on the import side is likely to be higher. It may be efficient to reduce the price on the export side of the constraint; but it may not be efficient to reduce the price on the import side of the constraint. The August 15 filing proposes a single PX Market Clearing Price within a zone, even in instances of Intra-Zonal Congestion, a feature that we have accepted for now and that SoCal Edison has not objected to. We are not persuaded that the use of Must-Run generation to alleviate the constraint merits modifying this feature.

Of course Must-Run generators may be called by the ISO to provide reactive power. In this instance, other generators other than the Must-Run generator may be required to increase their Energy production, because producing reactive power often reduces the ability of a generator to produce real power. Any resulting additional costs would paid in the first instance by the ISO as an Ancillary Service cost, and recovered through the ISO's charges for Ancillary Services. Thus, it would not be appropriate for the PX Energy price to change from the price underlying its Preferred Schedule.

PX Overcollection of Revenues

The California Commission comments that the ISO/PX's August 15 response to a Staff data request does not adequately explain the possibility of PX revenue overcollection. The California Commission also expresses concern with the PX proposal for adjusting PX revenues after the fact when its revenues from Energy market operations does not match its transmission Usage Charges owed to the ISO.

We agree that the ISO/PX response to the Staff data request does not explain how overcollection could occur. Example 2 in Attachment 6 of the response purports to illustrate a case where the net revenue collected by the PX in operating the Energy market would not match the total Usage Charges owed to the ISO. 520/ However, the discrepancy between revenue collections and Usage Charges occurs only because of an error in the example. If the error were corrected, there would be no discrepancy between net revenues and Usage Charges in the example. 521/

Section 3.9.2.7 of the PX Tariff states that in the event of such over- or undercollection of revenue, the PX will rebate or collect (as appropriate) the excess or deficit from PX Participants in accordance with the applicable PX Protocol. We expect that this Protocol will be among those that the ISO/PX intend to submit to us by November 1, 1997. In light of the errors in

520/ August 15, Filing, Appendix III, Response to Question 9 (pp. 9-10) Attachment 6 (pp. 127-132).

521/ The example incorrectly states on page 131 that Scheduling Coordinat 1's $30 generator in Zone A produces 75 MW, whereas the correct figu should be 125 MW (based on the example's earlier conclusions about scheduling adjustments on page 130). Scheduling Coordinator 1's $60 generator in Zone 2 is incorrectly assumed to produce 50 MW so that price in Zone 2 is assumed to be $60. However, the $60 generator wo actually produce 0 MW, and the price in Zone 2 would equal $55 (i.e. the marginal cost of delivering Energy to Zone B, which is the cost price) in Zone A plus the $25 Usage Charge). The PX would collect n revenue equal to difference in prices between Zones A and B ($25), w is identical to the Usage Charge it would owe to the ISO. Thus, the would be no over- or undercollection of revenue if Scheduling Coordinator 1 were the PX.

Similarly, for Scheduling Coordinator 2, the example incorrectly concludes on page 131 that its $10 generator in Zone A would produce MW and its $35 generator in Zone B would produce 0 MW. The actual production should be 75 MW from the $10 generator and 45 MW from the generator. Thus, if Scheduling Coordinator 2 were the PX, its energ prices would be $10 in Zone A and $35 in Zone B. Thus, its net reve would be $25 per MW of Energy transmitted between the zones, which i identical to its Usage Charge to the ISO, and there would be no over undercollection of revenues.

Attachment 6, we are unsure of the need for such a provision. However, we will review the Protocol and reconsider the CEC's concerns at that time.

VI. Companies' Market-Based Rate Proposals

In this order we conditionally accept for filing, without hearing or suspension, the proposed market-based rates filed by the Companies in Docket No. ER96-1663 for sales of energy through the PX. The market-based rate authority does not apply to the Companies' sale of ancillary services and also does not apply to the Companies' sales outside the PX. 522/

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. 523/ In order to demonstrate the absence or mitigation of market power, a transmission-owning public utility must have on file with the Commission an open access transmission tariff for the provision of comparable services. The ISO has filed an open access tariff governing the use of the Companies' transmission facilities. In addition, PG&E, SDG&E, and SoCal Edison have filed open access tariffs for the provision of comparable services over their local distribution facilities that are not subject to ISO control. Accordingly, we find that the Companies have satisfied the Commission's transmission market power standard for approval of market-based rates.

The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing. The Companies commit in their power sales tariffs that they will not sell power to, or purchase power from, any affiliate unless the Commission first approves such a transaction in a

separate filing under section 205 of the Federal Power Act, 16 U.S.C. □ 824d (1994). 524/ In addition, each of their marketer affiliates has submitted a code of conduct with the respective Companies (governing, for example, the pricing of affiliate sales and purchases of non-power goods and services and the exchange of market information) that satisfies the Commission's affiliate abuse requirements. We also note that the companies commit to sell all of their power into the PX for the first five years of ISO and PX operation. With these and related safeguards, we are satisfied that there are no affiliate abuse considerations of concern here.

522/ As described in our December 18 Order, the Companies are required to and sell only through the PX for the first five years of ISO and PX operation. December 18 Order, 77 FERC at 62,087.

523/ E.g., Progress Power Marketing, Inc., 76 FERC □ 61,155 at 61,919 (19 Northwest Power Marketing Company, L.L.C., 75 FERC □ 61,281 at 61,89 (1996); accord, Heartland Energy Services, Inc., et al., 68 FERC □ 61,223 at 62,060-63 (1994) (Heartland).

524/ See Edison Source, 76 FERC □ 61,200 (1996); Enova Energy, Inc., 76 □ 61,242 (1996); USGen Power Services, L.P., 73 FERC □ 61,302 (1995)

In order to demonstrate adequate mitigation of generation market power, each of the Companies have filed mitigation and monitoring proposals. The Commission found in its December 18, 1996 order that PG&E, SoCal Edison, and SDG&E may have horizontal generation market power and locational market power resulting from ownership and control of units that must be run for reliability. The Commission directed the companies to present mitigation proposals for both forms of market power. 525/ The mitigation and monitoring proposals are discussed below. As we explain below, we find that the mitigation and monitoring/enforcement proposals, as modified, adequately mitigate generation market power. However, to ensure that adequate mitigation is maintained, we are requiring certain monitoring and reporting requirements applicable to all Market Participants.

We find that the Companies' market-based rate applications, as modified, meet our standards for market-based rate authority. Accordingly, we will accept the Companies' proposed market-based rates for filing, to become effective upon commencement of ISO operations. We direct the Companies to report any changes in status promptly or before the end of the transition period 526/ in conjunction with an updated market analysis. 527/

A. PG&E's Market Power Mitigation Proposal

As a long-term structural mitigation measure, PG&E announced its intention to divest all 7,363 MW of its fossil-fired and geothermal generation. 528/ PG&E intends to sell the assets as soon as possible after obtaining the necessary regulatory approvals from the California Commission, with a target date of the end of 1998. PG&E claims that any market power found by the Commission would be temporary in nature and would abate completely when the asset sales are completed.

In the interim period before the assets are divested, PG&E contends that the mitigation measures it proposes are adequate. PG&E considers the

monitoring plan an important mitigation measure. PG&E commits to provide historical data to the ISO and/or PX upon request prior to commencement of PX operations, subject to appropriate protections for any confidential or proprietary data.

525/ December 18 Order, 77 FERC at 62,085 (1996).

526/ The transition period under the Restructuring Legislation, during wh a retail rate freeze is in effect and stranded cost recovery through Competition Transition Charge (CTC) will last until the earlier of M 31, 2002, or the date on which stranded costs have been fully recove See the Restructuring Legislation, Section 368(a). See also SDG&E Supplemental Statement on Market Power Issues, Attachment A, March 3 1997, p. A-3.

527/ We reserve the right to require such an analysis at any time.

528/ Answer of PG&E to Comments on Market Power Filing, June 23, 1997, p.

PG&E submitted an analysis to show that the Competition Transition Charge (CTC) and retail rate freeze reduce PG&E s incentive to raise PX prices. 529/ Under the Restructuring Legislation, the CTC is defined as the "headroom" between (i) the PX price plus other costs such as transmission and local distribution charges and (ii) the frozen retail rates. 530/ Any amounts collected through the CTC will be used to reduce stranded costs, which are defined as the difference between market value as determined by the asset sale price (if divested) or appraisal and the net book value of the plant. According to PG&E, any increase in the PX price reduces the CTC it collects. PG&E claims that this gives PG&E no incentive to raise prices.

PG&E also contends that the fact that PG&E is generally a net buyer of energy removes any incentive to raise prices. PG&E argues that any increase in revenues that PG&E would obtain as a seller of energy into the PX will be more than offset by the increased costs it bears as a buyer. PG&E states that it cannot pass price increases on to customers because of the retail rate freeze.

PG&E states that the only potential concern when it is a net buyer is the incentive to depress prices, or "predatory pricing." Depressing prices may be profitable because a lower PX price increases the CTC collected by the Companies, according to PG&E. However, PG&E claims that the possible benefits of increasing the CTC are eliminated because the operating losses incurred by bidding below marginal cost are not recoverable under the CTC. Therefore, PG&E concludes it will not have an incentive for predatory pricing. This conclusion notwithstanding, PG&E commits to bid at or above its variable cost in any calendar month or two-week period. 531/ PG&E prefers this two-week period rather than a shorter time frame, arguing that the cost of stopping and starting a unit justifies occasional hourly bids that are below hourly variable costs.

PG&E claims that when it is a net seller, even if it has the incentive to raise prices, it has no ability to do so. At these times, the abundance of low-cost energy eliminates any market power it may have. Moreover, PG&E claims it was a net seller for only 10 percent of the year in 1996, during winter off-peak times when it had excess hydro generation available. However, in response to the Commission's request that PG&E focus on mitigation, it

proposes that the ISO and PX each be authorized to order PG&E to file a cost-based bidding cap with the Commission, in order to prevent any incentive PG&E may have to raise prices.

529/ Answer of PG&E to Comments on Market Power Filing, June 23, 1997.

530/ Phase II Market Power Filing of PG&E, March 31, 1997, at 7. See also SoCal Edison's Proposed Market Power Mitigation Strategies, March 31 1997, at 10.

531/ Answer of PG&E to Comments on Market Power Filing, June 23, 1997, at PG&E states that this commitment is consistent with SoCal Edison's proposal to bid at or above variable costs over a two-week period.

To address the potential concern that PG&E would make low-cost generating capacity unavailable so that higher cost capacity would set the Market-Clearing Price, PG&E states that availability criteria could be used. However, it is concerned that it would be difficult to design appropriate criteria. 532/

PG&E claims that it will not earn profits from sales of energy into the PX from Must-Run units because it commits to relinquish its Restructuring Legislation rights to keep these profits. PG&E claims that any profits will be credited against the CTC.

In response to SoCal Edison, PG&E claims that it could not profit in the financial derivatives market and the monitoring program would in any event detect and prevent such behavior.

B. SoCal Edison's Market Power Mitigation Proposal

SoCal Edison plans to divest almost 10,000 MW of gas-fired generation, or about 80 percent of its generating capacity in California. 533/ The company plans to retain 1,600 MW of nuclear capacity in California, 1,200 MW of hydroelectric capacity in California, and 2,200 MW of capacity in jointly owned coal and nuclear power stations located in Arizona, Nevada, and New Mexico. SoCal Edison claims that it will have no ability to exercise market power over sales of energy and ancillary services after this divestiture. While SoCal Edison expressed the goal in its March 1997 filing of completing its divestiture by January 1, 1998, it provided a set of interim measures to mitigate market power until the divestiture is complete.

SoCal Edison claims that the retail rate freeze and CTC under the Restructuring Legislation mitigate the incentive to raise prices above competitive levels. When SoCal Edison is a net buyer, raising prices is not in SoCal Edison s interest because any increase in sales revenues is outweighed by a greater loss in the CTC. SoCal Edison presents data showing that in the past it has been net buyer during most times of the year and on an annual basis. When it is a net seller, it may have an incentive to increase the price because the increase in sales revenues outweighs the loss in the CTC. However, when SoCal Edison is a net seller, the volume of sales is generally small. Therefore, SoCal Edison concludes, the retail rate freeze and the CTC eliminate the incentive to exercise seller market power.

SoCal Edison notes that it may have an incentive to bid some of its generation below variable cost, if by doing so it can force down the market price sufficiently that the increase in the CTC is greater than the losses incurred by selling below cost. This will depend on supply and demand conditions. In order to mitigate this incentive, SoCal Edison commits that

532/ Answer of PG&E to Comments on Market Power Filing, June 23, 1997, at

533/ Southern California Edison Company s Proposed Market Power Mitigatio Strategies, March 31, 1997 at 8.

its revenues from the sales of energy and ancillary services to the PX and ISO will be greater than or equal to its variable costs (including start-up and no-load costs) during any rolling two-week period. 534/ Additionally, SoCal Edison proposes a 30-day triggering mechanism in the event the ISO determines, based on the results of monitoring, that further limitations upon SoCal Edison s ability to bid below variable cost are warranted. 535/

SoCal Edison asserts that the monitoring program will effectively remedy any remaining market power SoCal Edison may possess, including the incentive to raise prices during the small number of hours in which it is a net seller. To facilitate the monitoring programs, SoCal Edison commits to provide certain information, such as heat rate curves, start-up costs, and historical unit availability to the ISO. 536/

SoCal Edison proposes that if the ISO or PX finds that SoCal Edison is engaging in behavior that is driving the PX price above competitive levels, the ISO and PX each have the authority to require SoCal Edison to file with the Commission bid caps and availability criteria. These bid caps would apply to the gas-fired units which represent the bulk of SoCal Edison s biddable capacity and are the most likely vehicles for strategic manipulation of prices and output. 537/ SoCal Edison filed specific bidding criteria in March 31, 1997, but withdrew them on September 2, due in part to unspecified software limitations that will delay the existence of certain market mechanisms.

C. SDG&E's Market Power Mitigation Proposal

SDG&E concluded in its original market power filing on May 29, 1996, that it lacked market power in any relevant market larger than the San Diego Basin. 538/ Within the Basin, the simultaneous import limit (SIL) plus non-SDG&E generation is estimated to be less than load for 750 hours per year according to SDG&E. In those hours SDG&E generation must be run to meet load. According to SDG&E, this creates a theoretical ability to raise prices. SDG&E states that demand-side bidding holds potential to mitigate its market power resulting from import constraints in the future, but currently demand-side

534/ Southern California Edison Company s Proposed Market Power Mitigatio Strategies, March 31, 1997 at 24.

535/ Southern California Edison Company s Proposed Market Power Mitigatio Strategies, March 31, 1997 at 22.

536/ Southern California Edison Company s Proposed Market Power Mitigatio Strategies, March 31, 1997 at 22.

537/ Southern California Edison Company s Proposed Market Power Mitigatio Strategies, March 31, 1997 at 23.

538/ Supplement of Southern California Edison Company and San Diego Gas & Electric Company to Application for Authority to Sell Electric Energ Market-Based Rates Using a Power Exchange (May 29, 1996).

bidding is limited by institutional barriers and customer awareness. SDG&E claims that divestiture is unlikely to be an effective remedy for its market power in the San Diego basin in the near-term. SDG&E claims that the units may have little or no value and thus could be closed, which does not solve the reliability problem. Also, divesting one or both of the two generating plants would only create a duopoly in the Basin, which may not provide effective competition. Lastly, SDG&E claims that the ambitious divestiture plans of PG&E and SoCal Edison already put a strain on regulators.

SDG&E, like SoCal Edison and PG&E, discusses the effects of the CTC and retail rate freeze to reduce the incentive to raise prices. 539/ SDG&E also notes that it purchases energy to meet more than 50 percent of its load, which prevents SDG&E from profitably raising prices.

SDG&E describes how the Must-Run contracts mitigate its market power in the San Diego Basin. 540/ Of the three Must-Run Agreements, SDG&E expects to be under Agreement B. Agreement B assures that in all hours in which the contracted Must-Run unit is callable, prices received by Must-Run units for energy and ancillary services will be marginal cost. SDG&E states that the ISO Governing Board has chosen all of SDG&E's units for Must-Run status. 541/ SDG&E states that units under Must-Run Agreement B will have no ability to reduce prices because Agreement B contains a bid floor.

SDG&E claims that even if the ISO does not select some of its units for Must-Run status, these uncontracted units will not have market power. The units involved have high variable costs, as illustrated by their low historical capacity factors. According to SDG&E, these units would not raise the market price if withheld because their bids would not have been accepted anyway. And they would not be used to depress the price because the bid would have to be so far below their high variable costs that the losses would render it unprofitable. Also, SDG&E claims that any units not selected by the ISO for Must-Run status are likely to be closed because they would not recover their costs of staying in service.

SDG&E filed further mitigation measures on August 15, 1997. To prevent below-cost bidding, SDG&E commits to bid in such a way to cover variable costs, including start-up costs. If the ISO or PX finds SDG&E to be bidding anticompetitively, SDG&E proposes that the ISO and PX each have the authority to compel SDG&E to file bid caps. If any units are not covered under must-run contracts, SDG&E will credit back all earnings in excess of full cost recovery from sales of energy and ancillary services against the CTC. SDG&E will file

539/ SDG&E Supplemental Statement on Market Power Issues, Attachment A, M 31, 1997, p. A-3.

540/ SDG&E Supplemental Statement on Market Power Issues, Attachment A, M 31, 1997, p. A-8.

541/ Response of San Diego Gas & Electric Company to Staff Information Requests, August 15, 1997, p. 5. However, the ISO has not yet filed with us to confirm SDG&E's statement.

with the ISO and PX all information necessary to monitor its conduct, including heat rate curves, start-up costs, and unit availability.

June 6, 1997 Comments on Mitigation Proposals

Citing the Companies' own statements, commenters express concern that the Companies may actually have an incentive to deflate the PX clearing prices (i.e., by bidding below their variable costs) during the transition period when the retail rate freeze is in effect, because: (1) depressed PX prices reduce the Companies' purchased power costs by a greater amount than the lost gain on sales; (2) lower prices would increase the so-called "headroom" within which the Companies may recover the CTC; and (3) depressed prices reduce the revenues of the utility's competitors, thereby weakening or eliminating them. 542/ Cogeneration Council further contends that during the retail rate freeze period, consumers will not benefit from lower PX prices because their rates will be frozen. 543/

CCEM describes the companies' incentive to deflate PX prices as follows:

> [D]uring the transition years, before divestiture, if the Companies depress the PX clearing price by bidding below their short-run marginal cost, they end up net winners at the expense of competing Scheduling Coordinators. Specifically, what results is: (i) the Companies' UDCs, as mandatory PX purchasers, benefit from lower PX prices; (ii) other purchasers are attracted away from the bilateral market by the depressed PX prices; (iii) the cost to the Companies in connection with the below-cost bid is less than the savings to the UDC customers insofar as all clearing prices (and not just those bid by the Companies) were depressed; (iv) up to the rate cap, the Companies' costs not recovered in the PX bid are recoverable in the Companies' CTC; and finally (v) generators that compete with the Companies for sales into the PX will not recover fixed costs and may not be able to compete even at short-run marginal costs. 544/

CCEM urges that although it is questionable whether any one of the Companies acting alone could effectively implement such a scheme, the

542/ See, e.g., Comments of Cogeneration Council at 5-6; IEP at 5-6; NCPA 43; SMUD at 17, n.15 (supporting SoCal Edison's and PG&E's proposals monitor actively PX bids, and to require bid floors to be filed if market abuse is detected).

543/ Cogeneration Council at 5.

544/ CCEM at 33-34.

Commission should monitor whether the Companies ever combine in such a predatory pricing strategy. 545/

Cogeneration Council also disputes the Companies' assertion that the Companies will be unable to artificially depress prices by virtue of restrictions in the proposed Must-Run contracts. It states that it is not certain that all the Companies' facilities will be subject to Must-Run contracts. It further states that the Must-Run contract bid floor, which requires recovery of the Companies' variable costs, still permits the Companies to use their CTC and revenues from Must-Run contracts to recover a portion of their going forward costs outside the market and artificially depress prices to a level that reflects only variable costs. 546/

SMUD argues that it is concerned that PG&E is capable of exercising market power over Path 15. 547/ SMUD states that it has been curtailed between 60 and 150 times per season over the past four years. In its Preliminary Comments (filed March 31, 1997), SMUD argues that a few key generating units can affect important transmission paths. 548/ As an example, it contends that the output from PG&E's Morro Bay generating unit has a material influence on the south-to-north transfer limit of Path 15. SMUD contends that for a given set of pumping loads and Diablo Canyon Nuclear Power Plant production levels, the output of the Morro Bay unit can influence the Path 15 transfer limits by 860 MW. This alone could change the market price for energy in the Northern Zone, where SMUD is located, by a few mills, according to SMUD. 549/ It further contends that such market power concerns increase if the owner of the Morro Bay unit also owns generation in Northern California, because at times the owner could exert market power by gaming the operation of the unit to its advantage. Such market power concerns increase if that same owner also has control of some pumping loads and the Diablo Canyon plant, as there would be an opportunity for even greater influence over Path 15 capabilities, according to SMUD. 550/

EPUC/CAC assert that the Phase II filing overlooks transmission additions or upgrades as a potential mitigation measure and request that the Commission provide a forum for investigating such measures. 551/

545/ CCEM at 34.

546/ Cogeneration Council at 7-8.

547/ SMUD at 16.

548/ SMUD Preliminary Comments at 14.

549/ SMUD Preliminary Comments at 15.

550/ Id.

551/ EPUC/CAC at 4.

Several commenters question the adequacy of the Companies' mitigation measures. 552/ Cogeneration Council argues that: the Companies are only required to recover their variable costs instead of all of their costs; measuring their compliance over an extended period of time (two weeks to a month as proposed) enables the Companies to engage in predatory pricing during some hours; the Companies merely commit to the measures; the Companies will be able to price below cost for an extended period of time before the ISO can determine if there is anticompetitive behavior; and SoCal Edison's proposed mechanism applies only to its gas-fired generation, with no restriction after divestiture on its coal and hydroelectric resources. 553/

Some commenters contend that the Commission's reliance on the provisions of the Restructuring Legislation and the proposed price cap mechanism to mitigate market power is insufficient. SMUD says that any change in regulatory structure or regime (either by the California Commission or California Legislature) could raise new market power concerns because PG&E would retain the ability and incentive to exercise market power in the absence of those regulatory safeguards. 554/ Turlock contends that without a reliable, base line market power study, the Commission cannot determine whether the Companies' divestiture plans will be sufficient to alleviate market power. 555/ Turlock says the Companies' representation that the cap on retail prices will alleviate market power is vague.

Metropolitan and TANC argue that the Companies have not justified the periods selected for the ISO to use to determine their compliance with bidding rules (two weeks for SoCal Edison, one month for PG&E) when they are net buyers. 556/ Metropolitan notes that London Economics, an ISO/PX consultant, proposed a period of 24 hours. They also request that the Companies be required to propose how they will make up any shortfall at the end of the evaluation period to meet their commitments not to bid below variable costs on average at times when they are net buyers.

SoCal Edison suggests that it is speculative whether the retail rate freeze will be a limiting constraint on transition cost recovery. 557/ It contends that if the retail rate freeze does not limit a utility's transition cost recovery, that utility loses nothing from a transition cost amortization perspective if the PX price rises above the competitive level. In this situation, according to SoCal Edison, the utility's incentives to raise PX prices by exercising market power depend on how much of the increase in net

552/ See, e.g., Comments of Metropolitan at 61-62; SoCal Edison at 7.

553/ Cogeneration Council at 7-8.

554/ SMUD at 12.

555/ Turlock at 4.

556/ Metropolitan at 62-63; TANC at 130.

557/ SoCal Edison at 8-11.

revenues from sales of energy to the PX the utility can retain for its shareholders.

SoCal Edison further contends that the effectiveness of the retail rate freeze as a mitigation strategy could be significantly reduced if there are other sources of profits that can be earned by shareholders as a result of the exercise of market power in the PX. 558/ It suggests such a result from trading by the Companies of electricity-related financial derivatives and notes that PG&E has applied to the California Commission for authorization to trade such derivatives. It further contends that this problem is exacerbated by the ISO's and PX's inability to monitor "unregulated" markets, such as the derivatives market, in order to detect such activity.

SoCal Edison proposes that PG&E and SDG&E be required to propose effective mitigation strategies similar to SoCal Edison's, but tailored to those utilities' circumstances. According to SoCal Edison, such proposals should address the two ways a firm could attempt to exercise market power to raise PX prices: (1) by bidding excessively high prices, or (2) by withholding supply and thus creating an artificial shortage causing prices to rise accordingly. 559/

Several commenters propose full divestiture by all three of the Companies to mitigate market power. NYMEX believes that true divestiture would mitigate concerns about the effect of the CTC on bidding, but it notes that it appears that the onset of the PX will occur far in advance of meaningful divestiture by the Companies. 560/ Under these circumstances, it urges active monitoring of the operation of the PX in the early years. SMUD asserts that divestiture would serve to mitigate market power both in the transition and post-transition period. 561/

TURN/UCAN recommend divestiture of all of SDG&E's gas-fired generation as a condition for market-based rates, alleging that competition in the Must-Run market in the San Diego Basin is hampered because SDG&E is the only holder of emission allowances sufficient for a generating facility. 562/ USGen proposes that the Commission establish as a condition precedent to the approval of SDG&E's mitigation plan that SDG&E and the San Diego Air Pollution Control District (APCD) adopt a revision to APCD Rule 69 satisfactory to all interested parties that allows all generators access to the NO_X allowances

558/ SoCal Edison at 11-13.

559/ SoCal Edison at 16-17.

560/ NYMEX at 8.

561/ SMUD at 16.

562/ TURN/UCAN at 126-27.

available on an equal basis to SDG&E and SDG&E's facilities. 563/ TURN/UCAN recommend that approval of SoCal Edison's market-based rates be conditioned on the successful implementation of SoCal Edison's plan to divest 100 percent of

its gas-fired generation. 564/

TURN/UCAN also urge that market-based pricing for PG&E and SoCal Edison be conditioned on the divestiture of hydro generation because hydro-based producers may have a significant opportunity to game the ancillary services market under the most recently adopted protocols. 565/ They assert that unlike other sources of generation, a hydro facility can often defer its use of capacity at zero cost, by simply storing the water for later use. This would enable hydro generators to bid essentially a zero capacity reservation price for reserves, thereby capturing the market for such services, and then demand very high energy prices for whatever reserves are actually utilized, according to TURN/UCAN.

The California Commission supports the validity of the claim that the retail rate freeze and stranded cost recovery (CTC) are a disincentive for the Companies to raise prices in the PX. However, it states that this claim is based on dynamic assumptions that may change during the transition period. 566/ It will monitor these assumptions and alert the Commission to changes in the assumptions that would render the potential mitigating effect of the retail rate freeze and stranded cost recovery no longer valid. Further, it expects divestiture to take place early in the transition period. Thus, the mitigating effect of the retail rate freeze and stranded cost recovery may last long enough to allow divestiture to take place. Accordingly, it does not believe that a PX rate cap is necessary at the commencement of PX operations. 567/

NCPA questions several of the Companies' assumptions concerning mitigation of market power. It asserts that the assumption that all transmission in and out of California would be available to the PX at non-pancaked rates necessarily includes the large proportion of the interconnecting capacity owned by public entities. However, it argues that any approval by the Commission must be conditioned on a prior affirmative ruling by the Internal Revenue Service which will permit the public entities to transfer operational control of their transmission facilities to the ISO. 568/

563/ US Gen at 8-9.

564/ TURN/UCAN at 127.

565/ TURN/UCAN at 127.

566/ See also Comments of NCPA at 38.

567/ California Commission at 123-26.

568/ NCPA at 39.

NCPA asserts that the assumption that PG&E will be a net buyer of generation is highly speculative; it will depend on the future behavior of its customers, potential customers and competitors and hence is unknowable at this time. 569/

NCPA contends that even after the proposed divestitures by PG&E and SoCal Edison, the Commission cannot know whether the purchaser of the assets

would enjoy market power. It speculates that there could be few potential purchasers for the divested facilities, and a purchaser of one company's facilities may purchase the other company's facilities as well. According to NCPA, it is also unknown what the terms and conditions of such a sale would be. 570/

NCPA argues that the Companies failed to analyze the potential exercise of market power in the congestion market. 571/ It contends that after the initial schedules indicate there will be congestion, an entity having generation or load on both sides of the congestion could manipulate the price which would be paid on all transactions through the congested area by manipulating its adjustment bids. According to NCPA, control of the congestion bid market may have profound impacts on the distribution and amount of Usage Charges paid by Scheduling Coordinators that schedule across a constrained interface.

NCPA further contends that Market Participants could be significantly harmed by any entity that may control the forecast bidding of up to 40 percent of the load in any hour by intentionally over- or under-stating forecasted demand. 572/ It suggests that the potential gaming of the congestion market or the imbalance energy markets by such an entity, coupled with that entity's control of either generation or energy based financial derivatives, may result in windfall profits at the expense of other Market Participants. This issue has not been discussed, and the Commission may need to limit the magnitude of load to be represented by any one Scheduling Coordinator (other than the PX) or forecasted by any one UDC, as a form of market power mitigation, according to NCPA.

NCPA argues that the end of the transition period terminates the protection upon which the filing is predicated. 573/ It proposes that if the Commission grants market-based pricing, such permission should be restricted to the transition period. It would require a further affirmative showing of lack of market power for any applicant before granting market-based pricing for the post-transition period. At the very least, NCPA argues, the

569/ NCPA at 40.

570/ NCPA at 41.

571/ NCPA at 43-44.

572/ NCPA at 44-45.

573/ NCPA at 46-47.

Companies' obligations to make sales and purchases through the PX should continue until there is a showing of lack of market power.

TANC argues that there are no mechanisms proposed for: substitution of non-Applicant generation as Regulatory Must-Run generation; the renegotiation of contracts with Regulatory Must-Take or Regulatory Must-Run units; the elimination of any units from these categories; or the utilization of these units in a manner consistent with economic dispatch. 574/

Metropolitan recommends that the companies be required to reevaluate market power implications in light of their proposed mitigation strategies.

It wants such reevaluation to take into account any changes in geographic markets which result from the reconsideration of transmission limits and operating limitations. 575/ TANC proposes that if market-based rates are authorized, the Companies be required to submit a new market study every two years. 576/

Absent divestiture, IEP proposes the imposition of a bid floor requiring the Companies to recover all their fixed and variable components of the facilities' going forward costs in the market. 577/ EPUC/CAC proposes a bid floor that reflects the opportunity cost of supplying the service, which would include at a minimum variable operating costs (fuel and O&M). Resolution of a specific costing method for the bid floor should be consistent with the methodology adopted for the Must-Run agreements, according to EPUC/CAC. 578/

IEP contends that a utility recovering CTC can thwart competition for Must-Run agreements by bidding below its competitors regardless of costs, knowing that the CTC will make it whole. 579/ It recommends that market-based pricing be conditioned on the Companies' agreement not to seek CTC recovery for any losses they incur in the operation of their Must-Run facilities.

The California Commission comments that California law does not allow conversion of operating losses into CTC. 580/ It states that the combination of the legal prohibition and practical limitations should provide assurance that the Companies will not exploit predatory pricing practices.

574/ TANC at 128-130.

575/ Metropolitan at 60-61.

576/ TANC at 117.

577/ IEP at 10. See also Cogeneration Council at 8-9.

578/ EPUC/CAC at 23-24.

579/ IEP at 12.

580/ California Commission at 127.

CCEM urges the Commission to adopt the same comparable, unbundled billing and metering options as the California Commission has ordered for the direct access, retail market. 581/

Companies' June 23 Reply Comments

SoCal Edison opposes the above-variable cost bidding floor proposed by Cogeneration Council to mitigate the alleged CTC subsidy. 582/ It contends that stranded cost recovery does not subsidize utilities' sales in the competitive market because California law does not allow the CTC to cover the going-forward costs of the Companies' generation, except for going-forward costs of generation that is Must-Run. In any event, SoCal Edison states that it has committed to a variable cost floor.

Intervenors' proposals to require bid floors that exceed variable cost would lead to artificially high prices and an inefficient use of resources, according to SoCal Edison. It characterizes the intervenors' proposals as a collateral attack on Order No. 888 and the Commission's decision to permit the Companies to seek recovery of legitimate stranded costs in the transition to competition. 583/

SoCal Edison also opposes proposals to calculate the variable cost floor over a period shorter than two weeks. 584/ It explains that the variable cost floor is defined over a two-week period to take into account the costs of starting and stopping a generating unit.

PG&E argues that SoCal Edison does not explain how its availability standard would be applied. While it believes that the monitoring program could use historical availability of generation facilities as a yardstick for evaluating bidding behavior, that data should not be used to set strict availability requirements such as those that appear in the Must-Run agreements. 585/ PG&E contends that it would be impossible to apply any easily ascertainable availability standard for PG&E's generation that would have any meaningful relationship to whether PG&E actually was withholding generation from the market. It states that its fossil generation is comparatively old, and requires much maintenance; thus, the historical availability factors for those units swing considerably from year to year. It therefore is difficult to use historical data to accurately predict what a unit's availability will be in a particular year, according to PG&E. It asserts that such a requirement would be particularly inappropriate in light

581/ CCEM at 35-36.

582/ SoCal Edison, June 23 Comments at 20-21.

583/ SoCal Edison, June 23 Comments at 20.

584/ SoCal Edison, June 23 Comments at 23-24.

585/ PG&E, June 23 Comments at 9-10.

of PG&E's commitment to sell its fossil and geothermal generation. 586/ PG&E suggests that to the extent its availability falls below its historical availability, the ISO should be empowered to investigate further and, if there is no adequate explanation for the deviation, PG&E could be subjected to penalties negating any benefit realized from withholding capacity.

PG&E opposes the proposals to apply bid floors on an hour-by-hour basis because it ignores the impact of unit commitment and startup costs. It argues that in order for the market to reflect actual costs and thereby operate most efficiently, there should not be an artificial floor on bids during low load factor time periods. Instead, floors should be based on average variable costs determined over a reasonable period of time, as it proposed. PG&E states that it is willing to change its proposal from a one-month time period for calculating costs to the two-week rolling average contained in SoCal Edison's proposal. It considers that proposal to reflect an appropriate compromise between the competing goals of preventing predatory pricing and allowing sufficient flexibility to meet changing operational circumstances. 587/

PG&E argues that the possibility that it may at some point conclude that it could collect full stranded cost recovery through the CTC does not impact PG&E's incentives at the commencement of PX operations. 588/ It further argues that the California Commission's assertion that PG&E's incentives would change to the extent that PG&E switches from being a net purchaser to a net seller as a result of loss of load is misplaced because: (1) PG&E is entitled to CTC recovery from all of its existing customers even if they switch to another supplier, and its CTC recovery from those customers is tied to the PX price; and (2) PG&E's planned sale of all of its fossil and geothermal generation make it unlikely that PG&E ever will be a net seller even if it does lose considerable load. 589/

PG&E argues that SoCal Edison's suggestion that PG&E has an incentive to artificially keep PX prices high in order to retain increased profits associated with Must-Run facilities is not an issue, because PG&E is now selling all of those facilities. Moreover, PG&E has agreed under the terms of the ISO Must-Run contract proposal filed with this Commission and PG&E's CTC proposal filed with the California Commission that it will relinquish its rights under the Restructuring Legislation and credit Must-Run profits against the CTC. 590/

586/ PG&E, June 23 Comments at 11.

587/ PG&E, June 23 Comments at 13-14.

588/ PG&E, June 23 Comments at 15.

589/ PG&E, June 23 Comments at 15-16.

590/ PG&E, June 23 Comments at 16.

PG&E argues that SoCal Edison's argument concerning financial derivatives is misplaced because: (1) given its need to hedge against the risk of higher PX prices that could reduce its CTC collection, PG&E would have a strong incentive not to manipulate PX prices to profit in the financial market; (2) subsequent to manipulation, no rational business entity would enter into financial derivative contracts with PG&E, and PG&E would lose its ability to perform the hedging it desires; and (3) the monitoring program would detect any abuse of its market power. It also cites the legal prohibition against its recovery of any losses incurred as a result of making sales below variable costs. 591/

July 23, 1997 Reply Comments

The California Commission strongly supports PG&E s expanded divestiture and agrees with PG&E that the sale will greatly reduce any market power that PG&E is found to have. 592/ It asserts that PG&E s commitment to relinquish its rights under the Restructuring Legislation and credit Must-Run profits against transition costs mitigates a potential market power abuse by eliminating an incentive to artificially keep PX prices high.

SoCal Edison states that PG&E s June 23 Answer has addressed its concerns. 593/ It also urges that the Commission take steps to have the ISO

expeditiously elaborate on the details of the monitoring program, specifying: what cost, price and transmission data will be reported to the ISO and PX for monitoring; and how the existence of market power and supra competitive prices will be identified and addressed.

SMUD states that PG&E s proposals for full divestiture of fossil fired generation, agreeing to provide historical cost and availability factors, accepting SoCal Edison s proposal for filing bidding restrictions within 30 days, and requiring average bids into the PX over a rolling two-week period not be below total variable costs for that time period, address many of SMUD s market power concerns. 594/ However, SMUD maintains that decisions on whether and how to implement bidding restrictions should be left to the ISO and PX compliance divisions.

CAC/EPUC oppose SoCal Edison s proposed two-week balancing of variable costs and PX prices because, with the definition of variable costs proposed by SoCal Edison (as opposed to going forward costs) to be used in the balancing calculation, SoCal Edison will be able to drive competitors from the market, prohibit market entry and secure essentially a risk-free recovery of

591/ PG&E, June 23 Comments at 16-17.

592/ California Commission, July 23 Comments at 3-4.

593/ SoCal Edison, July 23 Comments at 1.

594/ SMUD, July 23 Comments at 2-3.

all generating units. 595/ Cogeneration Council argues that SoCal Edison has not provided any support for its claim that the two-week measurement period is necessary to account for unit starts and stops. 596/

Cogeneration Council strongly supports PG&E s divestiture proposal, but proposes that the Commission adopt appropriate mitigation measures to be effective prior to the completion of divestiture. Further, it maintains that the Commission must still address market power issues concerning PG&E s hydroelectric facilities. 597/

With respect to the Companies incentive to deflate PX prices, Cogeneration Council disputes SoCal Edison s argument that the Companies are not entitled to recover going forward costs from CTC. 598/ It asserts that under the Restructuring Legislation, SoCal Edison is entitled to receive CTC recovery for certain of its going forward costs, i.e., uneconomic fuel and fuel transportation costs incurred under contracts entered into prior to December 20, 1995 that are found reasonable by the California Commission. In addition, it asserts that the Companies are entitled to recover the CTC for going forward costs associated with Must-Run units that are needed for reactive power voltage support. Cogeneration Council further argues that it is not the subsidy created by CTC that concerns it; rather, the concern is that the Companies will seek to deflate market prices in order to increase the CTC and accelerate stranded cost recovery. Thus, SoCal Edison s argument is misplaced, according to Cogeneration Council.

San Francisco maintains that market power is a long-term issue and proposes that the Commission require the Companies to submit new market power

analyses in 2000 or 2001 that observe the Department of Justice 1992 Merger Guidelines. 599/ At that time, the market will have gained experience with competitive conditions, but the transition to a fully competitive marketplace will not yet be achieved, according to San Francisco. It states that these studies should reflect actual transmission usage, pricing patterns and market share.

Commission Response

As explained below, we find that the mitigation proposals, as modified, in conjunction with the monitoring/enforcement plan and Reliability Must-Run Agreements, adequately mitigate the Companies' generation market power for PX sales of energy. This finding is based in part on the existence of the retail

595/ CAC/EPUC Comments, July 23 Comments at 5.

596/ Cogeneration Council, July 23 Comments at 9.

597/ Cogeneration Council, July 23 Comments at 2.

598/ Cogeneration Council, July 23 Comments at 9.

599/ San Francisco, July 23 Comments at 2.

rate freeze under the Restructuring Legislation during the transition period and the mandatory sale of energy by the Companies into the PX. The Companies must file 60 days prior to the end of the transition period a market analysis that assesses the need for mitigation in the post-transition period.

Further, when PG&E and SoCal Edison divest most of their fossil-fired generation, they will substantially reduce their generation market power. PG&E's sale of 7,363 MW of fossil-fired and geothermal generation will leave it with 1,225 MW of "biddable" generation, or generation that is not committed under long-term fixed-price contract. SoCal Edison plans to sell nearly 10,000 MW of capacity, and retain 2,800 MW of biddable capacity. 600/ Both companies market share will be significantly reduced by these divestitures. However, it is not clear when the divestiture will be completed. Until that time, we agree with the California Commission and other commenters that effective mitigation measures must be in place. We will require the mitigation measures be in place until the Companies file and we approve a proposal to remove them.

As for a long-term solution for SDG&E, we agree with SDG&E that the development of demand-side bidding has the potential to mitigate market power in the San Diego Basin. We agree with NYMEX, SMUD, and TURN/UCAN that divestiture would also be effective. We will not require divestiture as a condition for market-based rates for SDG&E's PX sales, however, because the mitigation measures we are accepting are adequate to mitigate market power in the transition period. We direct the ISO and PX to monitor for market power in the San Diego Basin and to present information in their annual reports that would assist in the evaluation of this issue. 601/

During the transition period while the retail rate freeze is in effect, the retail rate freeze in conjunction with the CTC will reduce the incentive to raise prices when the Companies are net buyers. However, when the

Companies are net sellers, they may still have an incentive to raise prices, because the increased earnings from the higher-priced sales may outweigh the losses incurred by reducing the CTC.

Each of the three Companies has offered further mitigation measures against this remaining incentive to raise prices in the transition period. They propose that the PX and ISO have the authority to compel the Companies to file variable cost-based bid ceilings (bid caps) with the Commission if either the ISO or PX finds anticompetitive bidding. We find that, if there is evidence that the Companies have been exercising market power, bid caps may be an appropriate response. We direct the ISO and PX each to file pro forma bid caps with the Commission under FPA section 205 as soon as practicable. The bid caps would then be available to apply to any of the Companies upon a finding by the ISO or PX of anticompetitive bidding. The bid caps developed by the ISO and PX should be appropriate to the markets administered by each

600/ SoCal Edison, March 31 Comments at 9.

601/ The ISO proposes to file annual reports with the Commission and othe agencies. See ISO/PX June 23, 1997 Reply Comments at 111.

entity. We direct the Companies to submit to the ISO and PX all information necessary for them to develop bid caps. We will also require that any bid caps put in place may be applied to all units owned by the Companies that bid into the PX and ISO markets. We will not limit the caps only to gas-fired units as proposed by SoCal Edison.

To prevent the Companies from withholding capacity and thereby causing prices to rise, we find unit availability standards to be an appropriate response. We direct the ISO and PX each to file availability standards with the Commission as part of the mitigation proposal as soon as practicable. The availability standards should be appropriate to the markets administered by each entity. We direct the Companies to submit to the ISO and PX all information necessary for the ISO and PX to develop availability standards. 602/ The standards should be flexible enough to accommodate instances where an outage can be justified by the unit owner. We note that the ISO and PX will each be able to compare unit availability with the historical availability information provided by each of the Companies as part of the ISO's and PX's monitoring plans.

There also may be an incentive for the Companies to reduce prices below competitive levels which would accelerate recovery of stranded costs through the CTC. Regarding the claim by PG&E and the California Commission that the legal prohibition against recovering operating losses in the CTC prevents this behavior, this may be true. However, we do not see why one unit's operating losses could not be offset by the gains resulting from an increase in the CTC. We accept each of the Companies' commitments to prevent below-cost bidding. We direct the ISO and PX each to monitor for such below-cost bidding. The ISO and PX should compare revenues with variable costs for each generating plant to determine whether the Companies are bidding in such a way as to under-recover costs. To ensure that startup and shutdown costs are accounted for, the evaluation should take place over a rolling two-week evaluation period that rolls over day-to-day. We disagree with Cogeneration Council that the bid floor should be above variable cost to mimic the behavior of a company that tries to collect some contribution towards fixed costs, because sunk fixed costs should not affect current bidding behavior.

In response to NCPA's point that divestiture may simply transfer market power to the purchaser of the assets, the concern is premature. The issue may be addressed upon the disposition of the assets. In response to NCPA's point that the Companies failed to analyze the congestion market, we note that the monitoring plan discussed below addresses the ability to profit by creating transmission constraints.

In response to SoCal Edison's point that the mitigating effects of the retail rate freeze could be reduced by trading financial derivatives, the concern is premature. SoCal Edison states that PG&E has applied to the California Commission for approval of authority to trade in financial derivatives.

602/ The ISO and PX are also directed to develop appropriate pro forma availability standards applicable to all Market Participants.

In order to enforce these mitigation measures and to identify forms of market power abuse that are not easily predicted in advance, we also rely on the monitoring plan to be discussed below. We note that all three companies have consented to provide detailed information on marginal cost and unit availability to the ISO and PX to assist in monitoring. We accept this proposal and direct the Companies to provide information including, but not limited to, heat rate curves, start-up costs, and historical unit availability. We direct the ISO and PX each to develop consistent standards, where practicable, for the provision of such information.

Rehearing Requests on Market Power Issues

Palo Alto, Redding, Santa Clara, TANC and SMUD contend that the Commission failed to order the Companies to correct their market power studies and to properly study all of the relevant markets in order to determine the full extent of each Company's market power.

Palo Alto, Redding and Santa Clara agree with the Commission's finding that the Companies' market power studies demonstrate that the Companies will have market power at some times and in some locations. 603/ Palo Alto, Redding and Santa Clara also support the Commission's conclusions regarding the shortcomings of the Companies' studies.

Palo Alto, Redding and Santa Clara and TANC also state that they showed other shortcomings in the market power studies, not identified in the order, that also cause the Companies to understate their market power, particularly PG&E's failure to consider vertical market power issues. 604/ They contend that although the December 18th order discussed vertical market power, it is unclear whether the Commission relied on PG&E's erroneous assumption that the ISO will mitigate any vertical market power problems that otherwise might arise. (See PG&E's market power study, Appendix A at □ 6.) They argue that a vertical market power study is essential for the Commission to make a reasoned decision as to the adequacy of any mitigation measures.

Palo Alto, Redding and Santa Clara also dispute the accuracy of the product markets used in the Companies' market power studies, which used non-

603/ See December 18 Order, 77 FERC at 62,085.

604/ In the view of Palo Alto, Redding and Santa Clara, even after the ISO is established, the Companies may still be able to exercise vertical market power by controlling the availability of their must-run generation, through the timing of investments and maintenance, and thereby affect the availability of transmission. Companies' knowledge and control of their distribution systems and the continued ownership of their distribution facilities presents market power concerns, including potential for cross-subsidization and discriminatory access. See TANC's August 19, 1997 protest at 22-29.

firm energy and short-run firm capacity as a single relevant product market. They contend that the Companies failed to study long-term bulk power, transmission, ancillary services, and distribution services as relevant product markets.

Palo Alto, Redding and Santa Clara also complain that the Companies failed to perform a "first tier" analysis, and that the Companies' contention that they provided a refinement to the first tier analysis is unsupported, and not addressed in the December Order.

Palo Alto, Redding and Santa Clara also assert that the Commission failed to address TANC's contention that SoCal Edison and SDG&E misapplied the Commission's Market Share Screens, resulting in an understatement of their market power.

Palo Alto, Redding and Santa Clara further assert that by not requiring new market power studies, the Commission only was able to determine that mitigation is necessary. They contend that the shortcomings of the Companies' studies precluded the Commission from determining the full extent of the mitigation measures that may be required.

Palo Alto, Redding, Santa Clara and TANC also argue that the Commission erred by failing to apply its preferred market power analysis in concluding that it can determine the measures that are necessary to mitigate market power without a complete and correct analysis of market power.

New Energy Ventures filed a motion to revoke the market-based rates of SoCal Edison's power marketer affiliate Edison Source. Alternatively, it requests rehearing. According to New Energy Ventures, the Commission erred in failing to address the current market power of SoCal Edison. In its order accepting Edison Source's market-based rates for filing, the Commission consolidated the case with the WEPEX proceeding for consideration of the issue of generation dominance by Edison Source or its affiliates. 605/

605/ Edison Source, 76 FERC □ 61,200 at 62.045 (1996). In Edison Source, Commission held:

> [I]n light of SoCal Edison's own statements regarding transmission constraints into Southern California, and the possibility that these constraints could show generation dominance by SoCal Edison and thus by Edison Source, further consideration of generation is

appropriate. Additionally, because this issue also is presented in the WEPEX proceeding, we will consolidate this case with WEPEX and consider SoCal Edison's and thus Edison Source's generation dominance in the context of the WEPEX proceeding.

76 FERC at 62,046 (footnotes omitted). The Commission further state "We retain the authority to revoke market-based rate authority on a

(continued...)

Commission Response

In response to SMUD, the Palo Alto, Redding and Santa Clara, and TANC, we find it unnecessary for the Companies to file further market power analyses in order to show that their generation market power has been adequately mitigated. The mitigation measures adopted by the Companies are strong enough to mitigate market power significantly greater than the market power indicated in their market power studies. Moreover, we expect the quality of the information developed by the ISO and PX monitors to be far better and more useful than information that could be assembled in a filed analysis using the first-tier hub-and-spoke method as proposed. As a result, the ISO, PX, and regulatory agencies, including the Commission, will be able to use the information on actual observed behavior to respond to any observed exercise of market power.

Further, the Companies need not file market power analyses for transmission, distribution, and ancillary services because they do not seek market-based rate authority for these products. Moreover, the Companies need not analyze the long-term bulk power market because the Commission has found that the long-term generation market is competitive. 606/

We will deny New Energy Ventures' motion and alternative request for rehearing. The fact that at certain times, transmission limitations may exist for sales into Southern California does not per se establish that Edison Source will be able to exercise generation market power. In this proceeding, we have investigated SoCal Edison's market power filing and we have adopted mitigation measures and a monitoring program that will address any market power concerns. Since there are now only a few months before the ISO and PX operations commence and the market power mitigation measures discussed in this order go into effect, and any relief we could grant in Edison Source would in any event be prospective only, we see no need to pursue New Energy Ventures' allegations at this time. If New Energy Ventures has specific evidence that transmission constraints in Southern California permit Edison Source or its affiliates to exercise generation market power, it should bring this to the

605/ (...continued)

prospective basis if it is demonstrated that Edison Source or its affiliates possess generation market power." Id. n.14 (citations omitted).

The discussion above in this order addresses market power issues and mitigation measures prospectively from the date the ISO and PX comme operations. There we conclude that any market power which Edison Source's affiliates may have will be adequately mitigated by the

measures proposed. As a result, in this section of the order we add market power issues as they relate to the period before the ISO and operations commence.

606/ Order No. 888 at 31,657.

attention of the ISO or PX or file a section 206 complaint with the Commission.

VII. Monitoring

In the December 18 Order, the Commission required a detailed monitoring plan, including, at a minimum, a description of who is responsible for the monitoring; what information would be collected; what the criteria for identifying the exercise of market power would be; what reports and information would be submitted to the Commission; and what mitigation actions would be taken if the exercise of market power is identified. 607/ The March 31 filing includes a monitoring plan that, as stated by the ISO/PX, focuses primarily on the workings of the various long-term markets that are under the direct control of the ISO and PX. Furthermore, the ISO/PX states that the primary focus of the surveillance will be upon the behavior of the various Market Participants in each of these markets. 608/

Summary of ISO/PX Proposal

1. Organization

The Monitoring Plan filed by the ISO and PX place the ISO and PX in charge of monitoring their respective areas of administration. 609/ The ISO and PX would each establish compliance divisions; the two divisions are expected to cooperate and exchange information where appropriate. The divisions would have a full-time staff who are familiar with the day-to-day operations of the ISO and PX. The governors and employees would be subject to conflict of interest standards. 610/

The ISO and PX Governing Boards would establish committees of independent experts to review information submitted by the compliance divisions and to make recommendations to their respective Governing Boards. The compliance divisions would also be able to hire outside consultants to assist with their tasks.

2. Scope

The ISO and PX propose to focus on day-to-day behavior of Market Participants rather than on "macro-structural" issues. On structural issues, the ISO and PX roles would be limited to contributing information and views

607/ December 18 Order at 62,087.

608/ March 31 Filing, Volume IV, Appendix 7 at 1.

609/ ISO/PX Market Power Monitoring Plan, March 31 filing, Volume IV.

610/ See August 15 Filing, Appendix IV, Exhibits A and B.

for use in regulatory proceedings. The ISO and PX note that they will neither have the analytical capabilities nor the enforcement tools to deal with most of the structural issues. 611/

It is the stated goal of the ISO and PX to identify: (1) anomalous market behavior, i.e., behavior that departs significantly from normal competitive market behavior, such as the strategic withholding of capacity; (2) design flaws in the rules and protocols; 612/ (3) mischaracterization of units as Reliability Must-Run; (4) successful attempts to create transmission constraints to exclude competitors; (5) behavior other than market power that undermines the efficiency of the market. 613/

One set of indicators identified by the ISO and PX will be to monitor which Market Participants set the market price and how often. The ISO and PX would consider how often a given Market Participant sets the price when it was a net buyer versus a net seller, during peak versus off-peak hours, and compared to other Market Participants. The ISO and PX would also evaluate which Market Participants set the market price in particular segments of the supply curve.

The ISO and PX list bidding strategies as another area of monitoring. They would test correlations between bidding strategies and the pool price and between revised bids in response to the initial schedule and the pool price. They would compare offered capacity to total capacity to identify instances of withholding. To monitor for predatory pricing, the ISO and PX would compare costs to revenues.

3. Reports

The ISO and PX propose to compile separate annual reports on their activities and on the state of competition which would be submitted to the Commission, the CEC, and the California Commission. The ISO and PX also state that publication of information is intended to be used as a tool to prevent anti-competitive behavior.

In response to concerns that market participants on the governing boards would interfere with monitoring and enforcement, the ISO and PX note that the compliance divisions would have the discretion to refer reports to regulatory agencies even when the boards do not approve the release or agree with the findings. 614/

611/ ISO/PX Market Power Monitoring Plan, March 31 filing, Volume IV at 7

612/ August 15 Filing, p. 28.

613/ ISO/PX Trustee, ISO Market Power Monitoring Plan, Phase II filing, Volume IV.

614/ ISO/PX Reply Comments, June 23, 1997 at 111.

4. Data

The ISO and PX would each be able to rely on information in the public domain and information submitted to them in carrying out their respective functions. 615/ Information will also be collected and analyzed, principally by the ISO, with respect to the transmission system and its impact on the market place, particularly as to the causes of congestion. The ISO and PX would each create transparent information bases with the following specific items: (1) relationships between market-clearing prices and bidding behavior, including data on prices, bids, winning bids, and which entities set the price; (2) a comparison of bids of Market Participants when they are net buyers versus net sellers; (3) rebidding strategies during iterations of the schedule within the PX and between the PX and ISO; (4) data on unit availability over time; (5) market share data; (6) publicly available information on generating costs; (7) information on schedules submitted by Scheduling Coordinators on injection points, generation sources, and delivery points; and (8) call contract information. The ISO and PX may also use some of the information offered by the Companies, if the Commission decides that it is appropriate for them to do so.

The ISO and PX note that some of the information used by the ISO and PX would be kept confidential, such as individual bids. The ISO and PX state they would preserve the confidentiality of such information as they present reports.

The ISO and PX also state they would not have access to information on bilateral contracts, other than the limited information that is filed with regulatory agencies already.

5. Enforcement

The ISO and PX each would have a set of sanctions at their disposal when market power is identified. The ISO and PX describe the first response as correcting any market design flaws to solve the problem. Barring any market design remedy, the ISO and PX state that the ISO and/or PX may impose sanctions. The ISO and PX state that no sanctions would be imposed when behavior is not "illegal or improper." These remedies would be applied equally to all players in the market, irrespective of their historical category (e.g. as IOUs or municipal utilities). 616/ Sanctions could take the form of fines and suspensions of trading rights. Alternative dispute resolution (ADR) procedures would be used on allegations of aberrant market behavior. When the ISO or PX finds problems it deems to raise serious regulatory concerns, it would refer the issue to regulatory agencies and/or antitrust agencies. For example, if the ISO or PX decides that structural

615/ ISO/PX Trustee, ISO Market Power Monitoring Plan, March 31 Filing, Volume IV at 9.

616/ ISO/PX Trustee, ISO Market Power Monitoring Plan, March 31 Filing, Volume IV at 15.

change is necessary to resolve market power problems, it would refer the issue to regulatory agencies including the Commission.

June 6, 1997 Comments on the Monitoring Plan

The California Commission states that a comprehensive monitoring plan is critical to its and the Commission's efforts to address market power. It also seeks clarification regarding how the PX and ISO Compliance Divisions and the Market Surveillance Committee will interact with the California Commission and other local regulatory authorities.

The California Commission recommends that initial and on-going input into the development of market power monitoring indices by interested parties and especially regulatory and antitrust agencies is necessary. It further recommends that criteria for identifying market power and mitigation strategies and remedies for market power be further defined and explored in a technical conference. It also recommends that internal reports filed with the Commission be made available to the regulatory and antitrust agencies and that all final reports be public and submitted to the California Commission and other designated agencies. It would require these reports every six months for the first two years of the transition period, with the possibility of shifting to an annual reporting schedule revisited by all parties at that time. 617/

The CEC would require the ISO and PX to share all of the market data in Appendix 7 of the ISO Tariff with the CEC and the California Commission, subject to appropriate safeguards to protect confidential information. According to CEC, such a condition would enable the CEC to assist the ISO, the PX, and the Commission by providing independent and unbiased market oversight and thereby strengthen the public's confidence in the fairness of the market. Further, since the ISO and PX are regulated primarily by the Commission, they may be reluctant to share market information even with the California Commission. 618/

CIU contends that the ISO and PX proposals would create costly and unnecessary bureaucracies whose monitoring functions can be adequately performed by other ISO and PX mechanisms and regulatory authorities. 619/

As part of the overall market power mitigation, CCEM would require the ISO to re-evaluate annually the locational and service needs of the Must-Run

617/ California Commission at 138-48.

618/ Comments of CEC at 17-18. See also Comments of IEP at 14 (the Commission should require the ISO and PX to file an annual market po report).

619/ CIU at 2-3.

units in the California Control Area to assure that the services are being provided as economically as possible. 620/

EPUC/CAC argue that the ISO's monitoring plan lacks any procedure by which a Market Participant can gain access to information that may assist in identifying or confirming suspected abuse of market rules or market power. 621/ They request that the Commission direct the ISO to: determine, in conjunction with Market Participants, what specific information or databases will be regularly accessible to the public; and develop a protocol by which a Market Participant can gain access to the public databases. In addition, they request that the Commission establish a more rigorous procedure by which a Market Participant can identify and seek timely resolution of potential abuses of market rules or market power.

Turlock raises concerns over whether members of Governing Boards appointed from stakeholder constituencies may attempt to influence the actions of these monitoring institutions as to monitoring activities directed at these constituencies. 622/ Turlock proposes that the enforcement divisions of the ISO and PX be organized and operated in an "inspector general" or "ombudsman" framework to make them more independent of the Governing Boards. Turlock also recommends that the bias toward keeping information confidential rather than disclosing it should be removed from the monitoring plan. Further, it does not want to see employees of the ISO and PX restricted in their access to information.

NCPA wants to see the monitoring functions strengthened. 623/ It asserts that there must be assurance that the surveillance committees of the ISO and PX are able to cooperate fully with each other. Metropolitan and TANC comment that the ISO and PX should coordinate their monitoring plans and be authorized to take corrective action such as ordering cessation of abusive actions, the full restoration of amounts received as a result of market abuses, and the imposition of penalties. 624/ Metropolitan and TANC assert that the Commission should not regard monitoring as a remedy for the exercise of existing market power; instead, they want monitoring regarded as a safeguard against the exercise of future market power.

SMUD argues that because the Companies will not be required to buy and sell electricity through the PX after the transition period, the PX may not be

620/ CCEM at 35-36.

621/ EPUC/CAC at 44-45.

622/ Turlock at 11.

623/ NCPA at 47-48.

624/ Metropolitan at 63-64; TANC at 132.

a viable source of price information, at least during certain periods. 625/ It further argues that the ISO needs greater authority to impose sanctions for abuses of market power and to refer market power concerns to the Commission or antitrust enforcement agencies. In addition, it proposes that the ISO monitor the use of hydroelectric resources, particularly the availability of hydro units relative to historical patterns of use. SMUD also proposes requiring

that the Companies file their variable costs, including fuel, variable gas transportation, no load, start-up costs and unit availability. It also urges the Commission to withhold market-based rate authorization in the post-2001 period at this time in order to allow the ISO to study the market conditions and, prior to the end of the transition period, file its conclusions with the Commission, along with updated market power analyses by the Companies.

SoCal Edison contends that the ISO's and PX's monitoring plan is too vague and will not allow for the early detection of anticompetitive conduct. 626/ In order to have adequate data to monitor conduct, it proposes that the ISO and/or PX have from the beginning of the new market the type of historical cost and availability data that SoCal Edison proposed to submit to it. It also believes that equivalent data should be collected from suppliers other than the Companies because several other suppliers are likely to be large enough to have significant effects on market prices. At least initially, all generators or intermediaries bidding into the PX energy market, the ISO's ancillary services and energy balancing markets, and scheduling energy through the ISO should be required to submit information to the monitoring program, according to SoCal Edison. 627/

Turlock complains that the monitoring plan does not aggressively seek information and is vague with regard to sanctions. 628/ It opposes after-the-fact determinations by the Governing Boards because: (1) there is no advance disincentive to prevent market abuse; and (2) given the prohibition against retroactive ratemaking, an after-the-fact rule change may not be used to punish a participant that earlier abused its market power.

NCPA contends that the proposed ADR process allows a participant to manipulate the market and profit from doing so while it delays the ADR process. 629/ Turlock is concerned that the plan does not disclose how ADR would be employed to discipline the abuse of market power, who would be

625/ SMUD at 14-19.

626/ See also, Turlock at 7-10 (the monitoring plan lacks significant tee and will address only long-term market power issues, not short-term transition measures or divestiture issues).

627/ SoCal Edison at 13-15.

628/ Turlock at 12-14.

629/ NCPA at 48.

parties to such a process or how it would be triggered. It wants to see this approach better developed and described in advance of operations. 630/

June 23, 1997 Reply Comments on the Monitoring Plan

PG&E responds that it understands the concerns expressed by commenters about the lack of detail in the proposed monitoring program. It recommends that this issue be discussed in the technical conference proposed in the Companies' joint filing. 631/

July 8, 1997 Comments on the Monitoring Plan

SMUD comments that the monitoring plan should monitor for market power directly, monitor the bilateral market, and state without caveat that the ISO and PX should freely exchange information. In particular, SMUD argues, the ISO and PX should compare bids to marginal costs, determine whether units are being withheld from the market, and detect the creation of transmission constraints. 632/

Commission Response

We approve the monitoring plans submitted by the ISO and PX on March 31, 1997, subject to the changes ordered below. We direct the ISO and PX each to revise their monitoring plans posted on WEnet with these changes prior to commencement of operations and include these modifications in their comprehensive compliance filings. We also direct the ISO and PX to clarify their bylaws when they are refiled to incorporate the institutional aspects of the monitoring plan.

1. Organization

We agree with the ISO and PX that it is appropriate for monitoring to be done by a separate compliance division within each organization. This need not lead to excessive bureaucracy as claimed by CIU. The ISO and the PX will be intensely involved in the day-to-day operations of the market and as a result will be natural entities to assume this responsibility.

We find the division of monitoring responsibility between the PX and ISO, with each monitoring the markets it administers, to be acceptable. However, given the substantial overlap between the markets administered by the ISO and PX,

630/ Turlock at 14.

631/ PG&E, June 23 at 5-6.

632/ SMUD Comments, July 8, 1997, at 5-12.

633/ it is important that coordination between the two compliance divisions occur. The filing states that the ISO and PX expect to coordinate their operations and to share information. We agree with SMUD that coordination is critical to successful market surveillance and we strongly encourage them to coordinate their operations and to share information. To clarify the different areas of responsibility and different functions of the ISO and PX, we direct the ISO and PX to file separate plans, with details of each entity s scope, data, reports, enforcement, and proposed interaction with their counterpart.

2. Scope

We agree with some commenters that the program should be operational

when ISO and PX operations commence. Our granting of market-based rate authority at this time is in part based on effective monitoring programs being in place. We also agree with the ISO and PX that the programs should be permanent.

The issues and criteria outlined by the ISO and PX cover the range of market power issues we are concerned about. In particular, the comparisons of bids to marginal costs, analyses of unit availability over time and during different market conditions, and detecting the creation of transmission constraints will be important. The evaluation of market rules will also be useful in the on-going design of the market.

While we agree with the ISO and PX that they should be principally concerned with day-to-day behavior rather than "macro-structural" issues, their input on structural issues will be important. In particular, the ISO and PX should submit to us descriptions of any observed pattern of market power abuse that is not easily remedied with the tools at the disposal of the ISO and PX. The ISO and PX are well-positioned to develop a record of potentially harmful behavior even if their ability to correct certain problems is limited.

We acknowledge the concerns of the commenters who claim there is not enough detail in the monitoring criteria and standards. At this time, we will give the ISO and PX the discretion to determine the details of the monitoring plan. As they gain experience and as market conditions change, we will allow them the flexibility to modify these criteria. The ISO and PX should post on WEnet a detailed description of the modified criteria as they are developed. We will review the modifications when they are filed in a comprehensive compliance filing. Moreover, we direct the ISO and PX to include their monitoring plans in their respective tariffs.

In response to SMUD's concern that bilateral contracts be monitored along with sales into the PX, this concern may be premature. Initially, all

633/ For example, one of the stated indicators is bidding behavior at tim of transmission congestion, which could be observed by both the ISO PX monitors.

of the Companies' power will be sold into the PX and therefore the ISO and PX will monitor all of the Companies' sales. However, when the requirement to sell into the PX expires, we recognize that if a company has market power, it is likely to prefer to sell into the bilateral market if it can avoid surveillance by doing so. Therefore, we direct the ISO to include in its annual report a proposal regarding the extent to which bilateral contracts should be monitored. This proposal should specify which information should be collected by the ISO and which information must be kept confidential in order to prevent competitive disadvantage to any party.

We note there is significant emphasis in the ISO and PX proposed criteria for identifying abuses on whether a company sets the price or is on the margin. While this can be important, it is not a necessary condition for exerting market power. A company with significant infra-marginal generation in a market could cause prices to rise by withholding it from the market even if it is another company whose generators are on the margin. The ISO and PX should therefore closely monitor unit availability.

At the time when the ISO assumes more of a role in allocating firm transmission rights, we direct the ISO to monitor the ability of firms to profit from transmission rights by strategically increasing or decreasing output from generators. The ISO will be well-placed for this responsibility. 634/

In response to the numerous requests for a technical conference, we believe that it is premature to take this step. Once the ISO and PX have filed their detailed monitoring plans and the ISO and PX have been in operation for an appropriate period, a technical conference may be appropriate.

3. Reports

We find the ISO and PX proposal to allow the compliance divisions to have the discretion to submit reports directly to regulatory agencies to be a sound response to the concerns that the ISO and PX boards, composed in part of governors representing Market Participants, could block the release of such reports. Any reports submitted to the Commission should also be made available to the California Commission, the CEC, and the state regulatory commissions of any state which has one of its utilities participating as a Market Participant. We will not require the regular release of internal reports at this time for our purposes, as proposed by the California Commission, because it may stifle the free exchange of information and views within the ISO and PX.

We accept the ISO and PX Board proposal to present a report by the end of 1998 covering the first nine months of the year. We encourage earlier

634/ The Commission's July 30 Order required the ISO to file, by June 30, 1998, a plan to make firm transmission rights available to market participants beginning on January 1, 1999. 80 FERC at 61,427.

reports, either approved by the board or directly from the compliance divisions, but do not require more than an annual report, at least at this time.

While we approve of the concept of having the ISO and PX being authorized to impose sanctions, we have not yet approved any specific sanctions and are directing the ISO and PX to have our approval under section 205 before they impose any sanction. If and when we approve specific sanctions, we will require notification, via a brief summary, of any sanction imposed by the ISO or PX, along with the analysis underlying the action promptly after the sanction is imposed. In addition to analyzing market power problems, annual reports should evaluate the general functioning of the market and market rules, and provide an analysis of the ability of the various mitigation measures and penalties in effectively and efficiently preventing market power abuse.

In the course of analyzing the possible causes of market power abuses and in imposing sanctions, we expect that the ISO and PX will rely to some extent on information that is treated as confidential in their tariffs. While we do not object to the ISO and/or PX filing information with us pursuant to a request for privileged treatment, see 18 C.F.R. □ 388.112 (1997), to avoid any misunderstanding we clarify that the ISO and PX may be directed to provide us

with any information in their possession if we find it necessary to accomplish our regulatory responsibilities. We note that while the tariffs state that the ISO and PX need not keep confidential information that the ISO, PX, or Market Participants are required to disclose pursuant to applicable regulatory requirements, this would not apply to data that were not ordered to be made publicly available. 635/ The ISO and PX may file the information under □ 388.12 of our regulations.

4. Data Collection

We agree with EPUC and CAC that one important source of information that could assist the ISO and PX is complaints filed with the ISO and PX by Market Participants. Market Participants, both buyers and sellers, who observe market behavior during their normal course of business, may be well-positioned to identify problems. The ISO and PX should receive and pursue complaints that may lead to evidence of the exercise of market power. The ISO and PX should allow confidential complaints in order to improve the quality of and number of potentially useful complaints.

5. Enforcement

We generally support the enforcement process and the concept under which appropriate penalties (which have been filed with the Commission) could be ordered by the ISO and/or PX. However, we direct the ISO and PX each to revise their tariffs under section 205 to describe penalties that they may

635/ ISO Tariff Section 20.3.1; PX Tariff Section 15.3.2.

impose and describe the behavior that would trigger each penalty. We agree with the specific suggestions by TANC, Metropolitan, and PG&E that penalties should be proportionate to the profits estimated to be earned by the abuse of market power. However, the penalty should also be greater than the estimated profits in order to serve as a deterrent to market power abuse. We also urge the ISO and PX to use with caution the sanction of suspending a Market Participant's trading rights. This could have the effect of further withholding desirable resources from the market. We also direct the ISO and PX to develop pro forma availability standards applicable to all Market Participants as a necessary component of their sanction proposal. In addition, as part of their sanction proposal, the ISO and PX shall also consider the appropriateness of bid caps applicable to all Market Participants.

In response to NCPA regarding the use of ADR to delay the process, we think the ADR process can speed up the resolution of disputes prior to a filing with the Commission. For example, the parties to disputes may be able to negotiate a settlement or crystallize the issues in dispute.

VIII. Reliability Must-Run Contracts

The market power analyses filed by all three companies concluded that individual generating units that must be run for reliability purposes may have locational market power. 636/ To mitigate market power from Reliability Must-Run units, each Company proposed mitigation measures. PG&E and SoCal Edison

proposed "call" contracts which would allow the ISO to procure the needed service from these units at a pre-established price during the periods in which the units were Reliability Must-Run. SDG&E proposed to make the units available, have them bid into the PX at variable cost, and to place each unit under a performance-based mechanism. In its December 18, 1996 order, the Commission required that the Companies provide additional information with respect to these mitigation proposals and convened a technical conference to explore mitigation strategies. 637/

Summary of the ISO/PX proposal

On March 31, 1997, the ISO and PX filed a Master Must-Run Agreement which provided rates, terms, and conditions on Must-Run contracts. 638/ The Master Agreement includes three conditions, A, B, and C, for which there are separate agreements. Only one agreement applies to a unit at a time. The ISO may call on a unit after the PX auction clears, based on its reliability

636/ SoCal Edison, May 29, 1996 at II-69; SDG&E, May 29, 1996 at III-4, P July 18, 1996 at 14.

637/ December 18 Order 77 FERC □ 61,265 at 62,085-87 (1996).

638/ March 31 Filing, Volume IIa; see also July 23 Reply Comments at 73.

needs. 639/ All units deemed by the ISO to be Reliability Must-Run begin with the market-based approach, Agreement A. Agreement A is intended for units that can participate profitably in the market most of the time. Under Agreement A, the unit may sell into the PX or bilateral contracts up to a maximum number of hours per year, and retain any revenues earned in such sales. 640/ When a unit is called by the ISO, it receives a contractually specified price per MWh for energy and a pro-rata share of the unit's annual fixed costs. The ISO provides units with annual and monthly forecasts of its Must-Run needs, and sends dispatch notices a day-ahead and an hour-ahead of time, subject to operational limits and maximum output limits. There are no penalties for a unit owner refusing to provide service when called under Agreement A.

Agreement B is intended for units that can participate in the market profitably in some periods but not in others. 641/ The ISO may unilaterally switch a unit to Agreement B if the unit is not providing sufficient service under Agreement A. The Agreement also permits a unit owner to unilaterally switch into Agreement B. Agreement B provides an availability payment which covers the annual contribution to the initial capital investment, fixed fuel costs, fixed annual O&M costs, and annual auxiliary power costs; it also provides a payment for running costs when a unit is called to run. Units under Agreement B are allowed to participate in the market, but bids into the PX are subject to a price floor to prevent below-cost bidding and 90 percent of any revenues earned in excess of the running costs are credited back against the availability payment. Revenues from sales under bilateral contracts would also be credited back to the availability payment using a proxy price which is yet to be determined. The ISO provides annual and monthly forecasts of its Must-Run needs and sends day-ahead and hour-ahead dispatch notices. The ISO can terminate Agreement B if, for example, there are alternative sources available. Units under Agreement B that fail to

provide service when called on by the ISO lose a portion of their availability payment.

Agreement C is intended for units that are not expected to operate profitably in the market at any time. 642/ Owners of these units may unilaterally switch them into Agreement C. The ISO may not switch units into Agreement C. Once a unit is under Agreement C it may not return to Agreement A or B. Under Agreement C, the unit is paid its fixed costs including its annual recovery of its initial capital investment as an availability payment and its running costs when the ISO calls on the unit to run. The owner is not allowed to bid into the PX or to sell under bilateral contracts. A unit under Agreement C that fails to provide service when called on by the ISO loses a portion of its availability payment.

639/ August 15 Filing, Appendix III at 33.

640/ See Conditions of Must-Run Agreement A, Appendix Va, August 15 Filin

641/ See Conditions of Must-Run Agreement B, Appendix Va, August 15 Filin

642/ See Conditions of Must-Run Agreement C, Appendix Va, August 15 Filin

Comments on Reliability Must-Run Agreements

1. Must-Run Status

The ISO states that it is undertaking an independent review of Must-Run requirements to be completed before January 1, 1998. The ISO claims that it will consider all generation sources within the State of California in its selection of units for Must-Run status and will not defer to Market Participants in this effort. As of its August 15, 1997 filing, the ISO was in the process of identifying units for Must-Run status. The ISO states that it would periodically review the need for Must-Run contracts for specific units and in general. The ISO proposes to replace initial agreements in the "near term" with a more competitive process to maintain system reliability in a least-cost manner. 643/

EPUC and CAC argue that the ISO did not present adequate information on the criteria for selecting Reliability Must-Run units. 644/

LADWP contends that the ISO should consider the stranded costs of a Reliability Must-Run Unit when it considers the economics of canceling that unit's contract in order to obtain cheaper power under a new Reliability Must-Run agreement. 645/ LADWP would require that the total cost of the new unit including any stranded costs of the Must-Run unit it replaces be less than the total cost of any of the terminated Owner's other units located in same Area. 646/ The ISO disagrees. If a Reliability Must-Run Unit is uneconomic and is no longer required for reliability, there is no justification for expecting the ISO to continue paying for its stranded costs, according to the ISO.

LADWP opposes IEP's proposal to prohibit must-run generators from substituting units under ISO Tariff Section 3.2(b). According to LADWP, the provision has been clarified but it is not new. In addition, LADWP argues that the ISO will select the lowest cost unit, and that the owner of the must-run facility that substitutes a "Comparable Unit" will not collect any

more money than if the designated unit were operating, although it is likely that the substitute unit would be more expensive to operate. Thus, states LADWP, there is no "exploitation" or "profit-making at the expense of ratepayers." 647/

2. Must Run Agreement A

643/ ISO/PX June 23, 1997 Reply Comments at 88.

644/ September 2, 1997 Comments of EPUC and CAC at 4.

645/ ISO/PX June 23, 1997 Reply Comments at 89.

646/ LADWP at 47-48.

647/ LADWP comments, September 16, 1997, at 7-9.

IEP, Cogeneration Council, CMA, CLECA, and the California Commission comment that a penalty should be imposed on units under Agreement A if they do not provide service when called upon. 648/ In response, the ISO argues that it has adequate recourse in such situations because it can unilaterally switch a unit to Agreement B which gives the ISO more control. 649/

SoCal Edison argues that Agreement A creates a disincentive for units to participate in the market because such units will receive a higher price when called by the ISO. 650/ SoCal Edison predicts that since more than half of the gas-fired capacity in California may be declared Must-Run, this would create a major distortion in the market. SoCal Edison proposes that the ISO pay Must-Run units the difference between the Must-Run contract price and the Market Clearing Price at times when the Market Clearing Price is lower, in order to keep those units in the market. The ISO responds that it is not clear that generators have this incentive and that SoCal Edison's solution would impose unnecessary additional costs on the ISO and consumers. 651/

3. Reliability Must-Run Agreement B

Numerous commenters criticize Agreement B for covering all of a unit's fixed costs. 652/ They argue that when these units bid into the market, they are at an unfair advantage because they do not need to recover fixed costs. Some of these parties claim that Agreement B also grants recovery of some variable costs because of a mischaracterization of some costs as fixed, resulting in a further advantage. The result of this guaranteed recovery of fixed costs and some variable costs, the parties claim, is that these generators can profitably bid below marginal cost, or engage in anti-competitive predatory pricing. Such below-cost bidding squeezes out competitors and, by lowering the PX price, increases the stranded cost payment by customers, according to the commenters. Some parties suggest eliminating Agreement B altogether, while the California Commission advocates specifying a bid floor that mirrors the natural bidding constraints of participants in the competitive market.

The ISO replied to these criticisms of Agreement B by passing a resolution to maintain contracts A, B, and C temporarily, but to modify

648/ Comments of the California Commission, June 6, 1997, at 81-81. Submittals of the California ISO and PX, August 15, 1997, Appendix I Catalog of Issues, Part III, at 4.

649/ ISO/PX Reply Comments, June 23, 1997, at 93.

650/ SoCal Edison, June 6, 1997, at 6-9.

651/ ISO/PX Reply Comments, June 23, 1997, at 85.

652/ Limited Protest of IEP, Cogeneration Council, CMA, and CLECA Regardi Must-Run Contract Issues, June 4, 1997. Comments of the California Commission, July 8, 1997, pp. 16-19.

Agreement B by the end of October, 1998 with the intent of providing for less than 100 percent of the fixed and "going forward" costs. 653/ The ISO Governing Board commits that any such modifications satisfy the ISO s reliability obligations and take account of market efficiency, and the overall costs of procuring such services. The ISO claims that fixed cost recovery is a reasonable temporary measure because it is a reasonable price for providing reliability. The ISO also notes that it can terminate an agreement at any time if it is not needed and all units will undergo a review after twelve months. In order to prevent predatory pricing, the ISO states that the Agreement contains a revenue floor set at variable cost over a two-week period that applies to all units under Agreement B when they bid into the PX.

After the ISO commitment to improve Agreement B, CLECA, CMA, and the California Commission withdrew their protest and accepted the ISO Board s commitment. 654/ Cogeneration Council argues that waiting until October will not help because those who receive the fixed cost subsidy will still refuse to give it up. 655/ EPUC and CAC suggest postponing unit owners' ability to switch into Agreement B until the Agreement is improved. 656/

SDG&E expressed in its August 15, 1997 comments that it would have no objection to excluding from the availability charge any sunk costs recoverable as transition costs. 657/

Clearinghouse and CCEM expressed concerns about how revenues from bilateral sales by units under Agreement B would be credited back against the availability payment. 658/ Clearinghouse and CCEM do not support the use of the PX price as a proxy for revenues earned through bilateral sales. They prefer using the ISO s Real Time Zonal Imbalance Energy Price as a proxy. The ISO states that Imbalance Price is too volatile and the PX price is being considered as a proxy, but this has not been determined. The California Commission urges that this issue be resolved soon.

The California Commission, IEP, CMA, CLECA, and Cogeneration Council comment that a penalty should be imposed under Agreement B on units who do not

653/ ISO/PX Reply Comments, June 23, 1997, at 81-83.

654/ Comments of the Public Utilities Commission of California, June 6, 1

pp. 81-81. Submittals of the California ISO and PX, August 15 Filin Appendix I, Catalog of Issues, Part III, p. 3.

655/ Cogeneration Council, September 2, 1997, at 8.

656/ EPUC/CAC, September 2, 1997, at 4.

657/ Response of SDG&E to Staff Information Requests, August 15, 1997, p.

658/ See ISO/PX Reply Comments, June 23, 1997, at 90.

provide service when called upon. 659/ The ISO claims that the withholding of a share of the availability payment will be an adequate incentive for units to provide service. The California Commission, IEP, CMA, CLECA, and Cogeneration Council maintain that withholding payment may not always be sufficient incentive. Moreover, the parties argue that if the penalty is never needed, then it would never be used, and no harm would be done. The California Commission suggests that at a minimum the penalty should be equal to the cost of replacing the power that was not supplied. 660/

SoCal Edison argues that owners of units undergoing divestiture should be allowed to place units directly under Agreement B or C, rather than waiting for the 90-day notice period. 661/ According to SoCal Edison, the problem is that a new owner of a unit will not have the ability to assess the profitability of the unit, which is the purpose of placing all units under Agreement A at the start. SoCal Edison claims that this policy is confiscatory because it does not provide owners of these units a reasonable opportunity to recover their fixed costs during the first 90 days of operation. The ISO disagrees with this proposal. 662/ The ISO states that the consensus reached in the WEPEX process was that all Reliability Must-Run units would start under Agreement A.

4. Reliability Must-Run Agreement C

The California Commission, IEP, CMA, CLECA, and Cogeneration Council comment that Agreement C should include a penalty when units do not provide service when called by the ISO. 663/ The ISO claims that units would lose a part of their availability payment by failing to perform, and therefore have a strong enough incentive to perform.

Commission Response to the Must-Run Agreements

We accept the pro forma Must-Run Agreements for now, subject to the modifications described below. We will require the ISO to file changes to the Agreements, as it has proposed to do, by October 31, 1998, and will re-evaluate the appropriateness of the Agreements at that time.

659/ IEP, CMA, CLECA, and Cogeneration Council, June 4 at 6-11. Californi Commission, June 6, at 81.

660/ California Commission, June 6 Comments on Mitigation Strategies, at

661/ SoCal Edison, June 6 Comments on the Phase II Filing of the ISO and

at 9.

662/ ISO Reply Comments, June 23, 1997, at 86.

663/ IEP, CMA, CLECA, and Cogeneration Council, June 4 at 6-11. Californi Commission, June 6, at 81.

Then, as now, the Commission evaluates the pro forma Master Must-Run Agreement based on the following criteria. First, we consider whether the agreement mitigates the Companies' locational market power and whether the price charged under the agreement is just and reasonable. Second, we evaluate whether the price passed through by the ISO is just and reasonable. Third, we evaluate whether the agreement provides resources for maintaining reliability, consistent with ISO Principle No. 4, which states that "an ISO should have the primary responsibility in ensuring short-term reliability of grid operations." 664/

Must-run status issues

We do not rule on the selection of Must-Run units at this time because the selection has not yet been filed. This selection and the criteria used to select units for must-run status must be filed by the ISO with the Commission under section 205 of the FPA and accepted for filing prior to the commencement of ISO operations. When the selection is filed, we will evaluate the list based on the criteria outlined above. Consequently, the comments by EPUC and CCEM regarding the public availability of the criteria used by the ISO in Must-Run unit selection are premature at this time, but parties may raise that issue when the selection is filed.

In response to LADWP's proposal for the ISO to consider stranded costs when choosing Must-Run units, we agree in principle that the ISO should consider all costs when selecting units for must-run status.

Agreement A issues

We agree with CLECA and IEP that a penalty may be necessary at times to make sure units provide the service as required by Agreement A. A generator subject to Agreement A would retain 100 percent of the revenues it receives from PX or bilateral sales, even if the generator fails to perform when called by the ISO under its Agreement A contract. The market price for energy in the PX or in bilateral markets may, at times, exceed the price payable under a generator's Agreement A contract. At such times, a generator under Agreement A would have a disincentive to perform under Agreement A, unless a penalty for nonperformance were imposed. Indeed, a generator may have the greatest incentive to fail to perform during the times when it is most likely to possess market power. That is because the market price is most likely to exceed the Agreement A price when the generator is in a must run situation and thus is most likely to possess market power. The ISO/PX argues that a penalty under Agreement A is unnecessary because the ISO can unilaterally move a noncompliant generator to Agreement B. We believe that moving a generator to Agreement B may often be a poor remedy, especially for generators that are in a must run situation for a small number of hours. Shifting to Agreement B could impose substantially more costs on the ISO, since (as currently structured) Agreement B guarantees full fixed cost recovery to the generator.

664/ Order No. 888 at 31,731.

Moreover, generators under Agreement B are largely insulated from market signals, since a large percentage of the revenues that an Agreement B generator receives from sales into the PX and bilateral markets must be rebated against its availability payment.

Regarding the times when must-run units sell into the market, we reject SoCal Edison's proposal to pay Must-Run units the difference between the contract price and the market price at times when the market price is lower. We agree with the ISO that this would be too costly. Moreover, if the ISO limits Must-Run status to units that are truly needed and limits payments to those required to maintain a unit's availability, this problem will be mitigated. Units will be unable to profit by withholding supplies from the market in those circumstances when the unit is not truly a "Must-Run" unit.

It is not clear to us whether the ISO and PX statement, "the ISO does not call on the unit until after the PX market clears" 665/ refers to the initial PX preferred schedule or whether it refers to any revised schedule submitted to the ISO in response to the ISO's announced advisory congestion usage charges. In order to mitigate locational market power arising from congestion, the ISO should call on a unit after the initial PX preferred schedule is set, prior to congestion management. Otherwise, a unit could take advantage of the constraint and be dispatched at a high price. We direct the ISO to make this clear in a compliance filing.

Agreement B issues

Regarding the claims that Agreement B will cause predatory pricing, we disagree. The fact that Must-Run units are paid an availability payment which covers fixed costs should not allow them to profitably bid below variable or marginal cost. Bid profits are unaffected by the fixed availability payment. A generator would lose money in a given hour if it was dispatched when its marginal or variable costs exceeded the price, regardless of the availability payment. Even if the availability payment includes some variable costs as is claimed by some parties, the payment itself does not vary with output and therefore does not affect bid profits. Therefore, we do not expect Agreement B to cause below-cost bidding and the distortions that are purported to arise from it. Further, the revenue floor currently in Agreement B provides added assurance against below-cost bidding. Whether below-cost bidding arises from the CTC and the retail rate freeze is an issue addressed in the mitigation and monitoring sections above.

Despite certain problems resulting from full fixed cost recovery under Agreement B, we will accept the ISO's proposal on an interim basis. We note that the ISO has committed to revise the Agreement by October 31, 1998 and that no unit may be under Agreement B for the first 90 days of ISO operations. The ISO and the California Commission state that the agreement must be preserved in order to maintain units available for reliability. The proposal as it stands does not reduce efficiency or raise costs above today's cost-

665/ August 15 Filing Appendix III at 29.

based regulated levels. 666/ We accept the ISO's commitment to file revised contracts under Contract B by October 31, 1998. In that filing, the ISO must explain why the pricing formula and resulting prices in the contracts are just, reasonable, not unduly discriminatory or preferential for services provided under the contracts. Any prior agreements shall terminate the day on which the new agreement becomes effective.

We are not persuaded by the criticisms of the ISO's proxy price for use in rebating profits from bilateral sales. In contrast to Clearinghouse and CCEM, we do not consider it improper for the ISO to use the PX market clearing price as a proxy. The ISO may choose the PX price if it is a good indicator of the market price for energy. For public utilities we will review the appropriateness of the chosen proxy price when contracts are filed.

Regarding SoCal Edison's proposal to place units under Agreement B or C if they will be divested, we agree with the ISO Board that there is not adequate justification for treating these units differently from all other Must-Run units. The new owners of these units will have the same opportunity to switch into Agreements B or C as other owners have.

Regarding the suggestion of some commenters for an additional penalty for not performing under Agreement B, we agree with the ISO that the loss of the availability payment is likely to provide a sufficient deterrent to non-performance. Therefore, we do not see a need to revise the tariff at this time. However, we direct the ISO to consider whether the existing penalty is adequate when it revises Agreement B by October 31, 1998.

We direct the ISO to make the same clarification in Agreement B as in Agreement A regarding the time at which the ISO calls on a Must-Run unit. In order to mitigate locational market power arising from congestion, the ISO should call on a unit after the initial PX auction, prior to congestion management.

Agreement C issues

We are concerned that the restriction against units under Agreement C ever bidding into the market may unnecessarily deny the market access to potentially desirable sources of power. However, it is unlikely that units with low enough costs to be dispatched in the PX would opt for Agreement C.

Regarding the penalty provisions of Agreement C, we are persuaded by the ISO's argument that it would be costly for a unit not to perform under Agreement C as written. It would lose part of its availability payment and is prevented from making other sales through which it could recoup this loss.

666/ We note that SDG&E offered to modify Agreement B to exclude from the availability charge any sunk costs recoverable as transition costs. also note allegations that units under Agreement B may over-recover their costs by retaining some profits from sales into the PX.

We will accept Agreement C on an interim basis. We note that no unit may be under Agreement C for the first 90 days of ISO operations and it is unlikely that many units will choose to be under Agreement C. We direct the ISO to justify or eliminate the bidding restriction under Agreement C by October 31, 1998 when the ISO files to revise Agreement B.

IX. Transmission Control Agreement

The ISO/PX have submitted a Transmission Control Agreement that establishes the terms and conditions under which Transmission Owners will become Participating Transmission Owners, and the respective duties and responsibilities of each Participating Transmission Owner and the ISO. Each Participating Transmission Owner will transfer to the ISO Operational Control of certain transmission lines and facilities that will become part of the ISO Controlled Grid and will be controlled as part of the Control Area. Under the terms of the Transmission Control Agreement each Participating Transmission Owner will continue to own and maintain its transmission lines and associated facilities. Each Participating Transmission Owner will also retain its Entitlements and associated responsibilities.

Section 203 Authorization

In our November 26 Order we conditionally authorized the proposed transfer of control of the Companies' jurisdictional transmission facilities to the ISO. In that order we noted that the ISO had not yet been formed and consequently that the facilities subject to its control and the extent of its operational control had not yet been finalized. We concluded that it would be premature to grant unconditional section 203 authorization until the proposed agreements, which adequately specify the facilities to be transferred and the extent of the ISO's operational control over those facilities, are filed with and approved by the Commission. 667/

The November 26 Order directed the ISO to propose a procedure to advise the Commission (and all other parties) in a timely manner of subsequent transfers of operational control of jurisdictional facilities between the ISO and the Companies (e.g., maintaining an up-to-date list of ISO Controlled Grid facilities on its OASIS). The order required that to the extent the ISO determines that other facilities need to be transferred to its control in order to operate the ISO Controlled Grid reliably, the Companies must agree to transfer operational control of the additional facilities. The Commission stated that as a condition to receiving final authorization, the Companies must agree that they will honor any subsequent ISO determination with respect to the facilities it deems necessary to perform its control area operating functions. 668/

667/ November 26 Order, 77 FERC at 61,822.

668/ Id. The Commission also stated that the ISO should have the discret
(continued...)

The November 26 Order also required the ISO to become a member of the

WSCC and WRTA. The Commission stated that to the extent further Commission authorization is required for the ISO to fulfill expanded control area responsibilities, such as the imposition of sanctions, we would consider such requests in the Phase II filing.

The Phase II Filing

The August 15th Phase II filing contains a Transmission Control Agreement which specifies: 1) the transmission facilities that are to be transferred to the ISO's control; and 2) the extent of the ISO's operational control. 669/ The filing also states that, consistent with our Phase I determination, it is the ISO's expectation that a list of the facilities to be controlled by the ISO (The ISO Register) will be published and maintained on the WEnet. 670/

In addition, the August 15 Filing provides that the Companies have committed in the Transmission Control Agreement to turn additional facilities over to the ISO if the ISO determines that it needs to operate additional facilities in order to reliably operate the system. 671/ As proposed by the ISO, if the ISO determines that additional facilities must become part of the ISO Controlled Grid, the ISO will make a section 203 filing with the Commission in order to assume operational control over those facilities. The ISO will provide a copy of any such application to the affected Company. 672/

Commission Response

We note that the ISO has been duly constituted, the relevant transmission facilities that will initially form the ISO Controlled Grid have been finalized, and the extent of the ISO's operational control of the facilities has been specified in the Phase II filing. In light of these developments, and subject to the following conditions, we grant interim section 203 authorization for the transfer of operational control of the

668/ (...continued)
to own, and/or contract for, any monitoring or information technolog that it may require in order to reliably and efficiently manage the Controlled Grid. Finally, the Order provided that the Companies mus also agree to honor any ISO determination with regard to the monitor and information equipment the ISO may deem necessary to operate the Controlled Grid.

669/ See Appendix A to the Transmission Control Agreement.

670/ ISO Appendix 5 at 18.

671/ See Section 4.1.1 of the Transmission Control Agreement.

672/ See Sections 4.2 and 4.5 of the Transmission Control Agreement.

Companies' transmission facilities, identified in Appendix A to the Transmission Control Agreement.

As the Commission stated in our November 26 Order, facilities under ISO operational control may change because: (1) facilities may have multiple uses

and the uses of the facilities may change over time; and (2) in response to system conditions, the ISO may temporarily take control of facilities normally under the operational control of the Companies. 673/ The ISO proposes to maintain an ISO Register of those transmission lines, associated facilities and entitlements that are under the ISO's operational control on either a long-term or a temporary basis. We accept the ISO's proposal to maintain a comprehensive list available to the public and this Commission of all transmission facilities that are currently under its operational control. As stated in the November 26 Order, in order to ensure the reliability of the ISO Controlled Grid we believe it is essential that the ISO maintain an accurate account of which entities have operational control for specific facilities. Consistent with our earlier ruling, we will also require that the ISO maintain detailed historical records identifying the time period and entity having operational control of specific facilities. After the ISO has gained operational experience it may propose a time period after which the data may no longer be maintained.

We note that page 21 of ISO Appendix 5, filed on March 31, 1997, states that the relevant Transmission Owner is to make the appropriate regulatory filings in order to effectuate the transfer of control. We clarify that whenever the ISO, as a public utility, assumes operational control of the transmission facilities of a non-public utility (i.e., the non-public utility becomes a Participating Transmission Owner), the ISO must make a section 203 application file with the Commission. To the extent the ISO assumes operational control of transmission facilities owned by another public utility (i.e., the public utility becomes a Participating Transmission Owner), we direct the ISO and the affected public utility to make a joint section 203 filing with the Commission detailing the transfer of operational control.

As stated in Section 5.1.1 of the Transmission Control Agreement, the ISO will be a member of the WSCC and the relevant Regional Transmission Group (RTG). This is consistent with the directive in the Phase I order. With respect to the ISO's proposal to impose sanctions on those entities whose operation and maintenance practices either cause or prolong a response to an outage, we note that the ISO has not yet filed a specific proposal. We therefore direct the ISO to timely file and receive an authorization, prior to implementing any such sanction, a complete proposal which details the amount of, and justification for, any sanctions on parties that fail to properly maintain and operate their respective transmission systems.

We note that details of the transfer of necessary dispatch control facilities (e.g., control centers, energy management system computers, telecommunications and supervisory control and data acquisition systems) from

673/ November 26 Order, 77 FERC at 61,023.

the Companies to the ISO have not been finalized. Any such transfer will be the subject of a future order.

Other Issues Related to the Transmission Control Agreement

Contested Issues Identified by the ISO/PX

Western contends that Transmission Control Agreement 5.1.1,

which prevents the ISO and Participating Transmission Owners from taking positions before the WSCC or an RTG inconsistent with a decision reached in binding arbitration, should be eliminated as an impediment to open and free discussion. 674/

Transmission Control Agreement Section 3 provides that a Party may apply to withdraw from the Transmission Control Agreement on two years' notice subject to obtaining all necessary regulatory approval. Western contends that Transmission Control Agreement Section 3.3 should be amended to give the parties to the Transmission Control Agreement the unilateral right to withdraw subject only to a reasonable notice period. 675/ Western and Turlock argue that the basis for determining which facilities should be turned over to the Operational Control of the ISO under section 4.1.1 is inappropriate. Rather than basing the determination on the distinction between transmission and distribution facilities, Western and Turlock argue that the determination should be based on whether or not the facility is required for reliability. 676/

Metropolitan contends that the Transmission Control Agreement should provide that the ISO has the right to return facilities that the ISO no longer requires. Metropolitan argues that users of the ISO Controlled Grid should not have to continue to pay the Transmission Revenue Requirement for facilities that are no longer required by the ISO or no longer meet the criteria for being treated as part of the ISO Controlled Grid. 677/

LADWP contends that the ISO should not have authority under Transmission Control Agreement Section 4.5.2 to take temporary control of facilities for the purpose of determining whether control of such facilities will aid the ISO in meeting reliability criteria or pending the resolution of a dispute in relation to the ISO assuming permanent authority. LADWP contends

674/ Western at 57-58.

675/ Western at 84.

676/ Western at 72; Turlock at 36-38.

677/ Metropolitan at 52-53.

that Section 4.5.2 should be amended to provide owners with compensation for the use of the facilities, that the control should be subject to Existing Contracts and that the temporary control should not be interpreted as submitting those facilities to the Commission's jurisdiction. 678/

LADWP, TANC, NCPA, and CMUA contend that a Participating Transmission Owner should have the unencumbered right to sell or dispose of its facilities and Entitlement subject only to notifying the ISO. 679/ Under Section 4.4, a Participating Transmission Owner may not sell, dispose of or encumber its facilities or sell, assign, release or transfer its Entitlements without the prior written consent of the ISO. Any such consent

shall be conditioned on the transferee assuming the obligations under the Transmission Control Agreement regarding such facilities. This provision does not require the transferee to accept Participating Transmission Owner status (which would have the effect of obligating the transferee to designate all of its other transmission facilities as part of the ISO Controlled Grid). These parties believe that the value of Participating Transmission Owners' facilities will be diminished if ISO consent is required and that such consent is not necessary for the protection of the ISO Controlled Grid. LADWP also proposes that the only restriction on the sale of facilities should be that the reliability of the ISO Controlled Grid would meet a "standard which would have existed if the subject facilities had never been included in the ISO Controlled Grid." 680/

Transmission Control Agreement Section 9 sets out the rules for handling System Emergencies. Section 9.2.1 provides that Participating Transmission Owners shall comply with all directions from the ISO regarding the management and alleviation of System Emergencies unless such compliance would impair the health or safety of personnel and/or the general public. LADWP contends that Participating Transmission Owners should also have the right not to follow the ISO's orders if it believes those orders are likely to cause serious damage or destruction to its facilities. 681/

Section 2.3.3 provides that Participating Transmission Owners or Municipal Tax-Exempt Transmission Owners which have issued Tax-Exempt Debt will not be compelled to do anything that "violates restrictions applicable to transmission facilities

678/ LADWP at 59.

679/ LADWP at 52-54; TANC at 101-103; NCPA at 36; and CMUA at 29-32.

680/ LADWP at 54.

681/ LADWP at 58-59.

financed with Tax-Exempt Debt or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995." TANC, NCPA, Modesto and CMUA believe that the phrase "existing as of December 20, 1995" should be deleted from Section 2.3.3. 682/ These parties argue that the phrase is unnecessary and unreasonable as some Municipal Tax-Exempt Transmission Owners have used Tax-Exempt Debt to finance facilities since December 20, 1995, and others have refinanced facilities built prior to that date.

June 23, 1997, ISO/PX Reply Comments

With regard to Western's argument, the ISO/PX notes that Transmission Control Agreement Section 5.1.1 provides that the ISO shall be the designated Control Area Operator for the ISO Controlled Grid and shall be a member of the WSCC and the

relevant RTGs in that capacity. This section restricts the ISO and Participating Transmission Owners from taking any position before WSCC or an RTG that is inconsistent with a binding decision reached through the ADR Procedure. 683/

The ISO/PX argues that this section will not impede free and open discussions. The reason for restricting both the ISO and Participating Transmission Owners from raising issues before the WSCC or an RTG that have been resolved using the ADR Procedure is to ensure that decisions reached under the ADR Procedure are not circumvented by allowing parties to again contest the same issue before the WSCC or an RTG. The ISO/PX argues that this section is necessary to ensure that the ISO and Participating Transmission Owners present a united front in the WSCC and all relevant RTGs.

With regard to Western's argument that the Transmission Control Agreement should include a shorter notice of termination period, the ISO/PX states that it objects to a shorter notice period, noting that the ISO would have no time to assess the impact of the withdrawal on the ISO Controlled Grid, or its ability to maintain reliability or manage Congestion. The ISO Tariff has not been designed to facilitate withdrawal of a Participating Transmission Owner and the unwinding of a restructuring according to the ISO/PX. Also, the ISO/PX believes that the withdrawal of transmission assets from the ISO Controlled Grid may frustrate the legitimate commercial expectations of Market Participants which enter into long-term commercial contracts on the basis that access to certain transmission facilities will remain subject to the ISO Tariff.

682/ TANC at 26; NCPA at 9; Modesto at 8-11; and CMUA at 8.

683/ ISO/PX June 23, 1997 Reply Comments at 301.

These Market Participants should have some means of pointing out to the appropriate regulatory authority (which in this case should be the Commission) the impact on them of a withdrawal of transmission facilities from the ISO Controlled Grid and to argue that such withdrawal, if it is to be permitted, should be subject to conditions that safeguard their legitimate interests. 684/ As a public utility, the ISO/PX notes that it may also require Commission approval to relinquish operational control over interstate transmission facilities unless the Commission determines in this proceeding to give Participating Transmission Owners a unilateral right to withdraw. 685/

In response to Western's and Turlock's proposal to modify Section 4.1.1 of the Transmission Control Agreement, the ISO notes that it has responsibilities under Section 345 of the Restructuring Legislation to ensure the reliable operation of the transmission grid. The test used in Transmission Control Agreement Section 4.1.1 is founded on the Commission's Order No. 888 technical and functional test to distinguish transmission from local distribution. In the ISO's judgment the test provides a reasonable means to fulfill its obligation to ensure reliable

operations. Western and Turlock have not shown this test to be unjust and unreasonable, but merely argue for a different standard more to their liking. The ISO argues that the Commission may not change the provision of a filed tariff unless the Commission first determines that a contested provision is unjust and unreasonable, and that Western and Turlock have not met this test. 686/

In response to Modesto's argument that the Transmission Control Agreement should provide for the return of facilities from the ISO, the ISO/PX state that there are no foreseeable circumstances in which it would be appropriate for the ISO unilaterally to relinquish Operational Control over transmission facilities that have been incorporated into the ISO Controlled Grid. As a legal matter, such action would be likely to require the authorization of the Commission and, for practical reasons, the agreement of the owner of those facilities, which would then become responsible for having to control them. 687/

In response to LADWP's argument regarding the assertion of temporary control over facilities, the ISO/PX points out that Transmission Control Agreement Section 4.5.2 authorizes the ISO

684/ ISO/PX June 23, 1997 Reply Comments at 307.

685/ Reply Comments at 307-308.

686/ See, Central Iowa Power Co-op v. FERC, 606 F.2d 1156 (D.C. Cir. 1979

687/ ISO/PX June 23, 1997 Reply Comments at 315.

to assume temporary control over facilities: (1) to deal with imminent System Emergencies; (2) to explore (for up to 90 days) whether control of such facilities will aid the ISO in meeting reliability criteria or to operate its Control Area; or (3) pending the resolution of a dispute in relation to the ISO assuming permanent authority under Section 4.5.1. 688/ The ISO/PX assumes that LADWP does not oppose having the ISO assume temporarily control facilities to deal with System Emergencies (provided that it does not continue to have control after the emergency ends). 689/ The ISO/PX also assumes LADWP does oppose the ISO having temporary control of facilities while determining whether control of such facilities will aid the ISO in meeting reliability criteria or pending the resolution of a dispute over the ISO seeking to assume permanent authority. 690/

The ISO/PX notes that the Commission's November 26 Order emphasized that the ISO must independently determine which facilities it deems necessary to fulfill its Control Area responsibilities. 691/ Therefore, the ISO/PX argues, it seems reasonable for the ISO to have the right to temporarily control facilities that it thinks it might need in order to have a rational and practical basis for determining whether permanent control of such facilities is required. The ISO/PX also objects to compensating Participating Transmission Owners for exercising temporary control over facilities.

In response to LADWP's, TANC's, NCPA's, and CMUA's arguments regarding the sale and disposition of property, the ISO/PX states that as Control Area Operator for the ISO Controlled Grid, it has a legitimate interest in reviewing and, if necessary, objecting on reasonable grounds to a proposed transfer of ownership rights in transmission facilities under its Operational Control. The ISO needs to be satisfied that the transfer will not diminish its Operational Control over those facilities or impose new restrictions that would unduly impair its ability to meet its obligations to Market Participants serviced under the ISO Tariff.

688/ In relation to the ISO assuming temporary control pending the resoluti of disputes over permanent control, in the event that the Transmissi Control Agreement is amended to provide that the ISO will assume ful control of facilities subject to ADR proceedings (see the discussion this point at Section XIV. Part H), this provision will also be amen as the ISO will not need temporary control pending resolution of disputes.

689/ ISO/PX June 23, 1997 Reply Comments at 320.

690/ Transmission Control Agreement Sections 4.5.2 (ii) and (iii) respectively.

691/ 77 FERC at 61,822.

The ISO/PX also indicated that the factors that it would consider in evaluating a proposed transfer are similar to those that it will consider in reviewing an application to become a Participating Transmission Owner. 692/

The ISO/PX argues that LADWP's proposed test for allowing a sale of facilities is inappropriate. Because the ISO is required to ensure reliability of the grid that it actually controls at the time of the proposed sale or transfer, a hypothetical assessment of reliability as if the relevant facility had never been transferred to the ISO's control is irrelevant. The ISO/PX also states that it would be impractical or impossible to undertake an assessment of reliability on the basis that a particular facility had never formed part of the ISO Controlled Grid.

In response to LADWP's argument that a Participating Transmission Owner should not have to follow the orders of the ISO if such orders may result in damage to equipment, the ISO/PX states that in an emergency the ISO needs to be certain that its orders will be followed. 693/ In addition, the ISO/PX states that it will be financially responsible for any damage caused to transmission facilities if it acts negligently in issuing operating instructions. 694/

In response to parties' concerns with regard to Section 2.3.3 of the Transmission Control Agreement, the ISO/PX state that this restriction was included in the Transmission Control Agreement because, as noted by the Parties, it is a requirement

under AB 1890. The ISO/PX state that the Commission should take into consideration the California State Legislature's intent and goals when reviewing the Phase II Filing. The Restructuring Legislation contains a clear expression of the intent regarding the grandfathering of protection for certain tax-exempt financed

692/ Examples of the factors include the following: Is the proposed transf being properly authorized by any necessary regulatory action? Is th proposed transferee able to comply with its obligations under the Transmission Control Agreement in relation to the transferred facilities? Is the transferee already in default on its obligations under the Transmission Control Agreement or the ISO Tariff? Will th transfer create new encumbrances that will adversely affect the ISO' ability to exercise Operational Control over the facilities? Will t proposed transfer increase the extent of joint ownership of transmis facilities, raising the possibility of operational problems if one o more of the joint owners seek to withdraw from the Transmission Cont Agreement?

693/ ISO/PX June 23, 1997, Reply Comments at 326.

694/ See Transmission Control Agreement Section 22.1.

facilities. While the ISO/PX appreciates the concerns of Parties relating to tax-exempt facilities that may not fall within this "grandfather" clause, the ISO/PX contends those Parties should take their concerns to the California Legislature. 695/

September 2, 1997 Comments

The California Commission recommends that the Transmission Control Agreement be made a part of the ISO Tariff, since many sections have general applicability as tariff provisions. The California Commission recommends that Transmission Control Agreement section 10.4.3 be amended to give the ISO unfettered inspection authority. Further, the California Commission proposes to provide the ISO authority to change any maintenance or operation standard, without limitation by the recommendations of the Technical Advisory Committee, to receive metering data directly from any entity on a real time basis, to own or contract for meter or information technology needed to operate the grid and to place the equipment at any location or facility it deems necessary. 696/

The California Commission requests that the definition of Operational Control be changed to allow the ISO the option to assume the actual physical operation of the lines and facilities. 697/ Similarly, the California Commission recommends that Transmission Control Agreement section 6.1.1 be revised to allow the ISO to assume physical operation of any portion of the Participating Transmission Owner's facilities or to assign maintenance of the facilities to a third party. The California Commission also contends that Transmission Control Agreement section 10.3 inappropriately gives the Participating Transmission Owners, rather than the ISO, the responsibility for developing

and implementing interconnection standards, and section 12.3 inappropriately requires the ISO to consult with Participating Transmission Owners to develop standards and mechanisms for incentives and penalties. 698/

The California Commission opposes the revision to Transmission Control Agreement Sections 2.2.3 and 2.2.4 which would now require the ISO to allow an entity to become a Participating Transmission Owner pending the outcome of ADR procedures challenging the entity s eligibility, unless the ISO

695/ ISO/PX June 23, 1997, Reply Comments at 305.

696/ California Commission at 28-29.

697/ Id. at 29

698/ Id. at 30-31.

determines that it will impede reliability or cause the ISO to breach its reliability obligations. 699/

The Companies oppose the proposed revision to Transmission Control Agreement Section 2.2.1(viii), contending that all Participating Transmission Owners must file a Transmission Owner Tariff, whether or not they are subject to Commission jurisdictional. 700/ The Companies assert that all Participating Transmission Owner applicants should face the same requirements for participation, and should provide nondiscriminatory and reciprocal transmission access under identical terms and conditions. While the Companies recognize that the Commission cannot require non-public utilities to file a Transmission Owner Tariff, conforming Transmission Owner Tariffs are a necessary participation requirement to ensure open comparable access by all Participating Transmission Owners. The Companies suggest a narrow exception for a potential Participating Transmission Owner that does not own facilities, intends to transfer Entitlements to the ISO, and does not propose to recover any revenue requirement through the Transmission Owner Tariff. 701/

DWR recommends that Transmission Control Agreement Section 2.2.5 also be modified to indicate that non-jurisdictional applicants are not required to file Transmission Owner Tariffs, consistent with the filed modifications to Transmission Control Agreement Section 2.2.1. DWR recommends that Transmission Control Agreement Section 10.3.1 be modified so that an entitlement holder need not develop technical standards for a transmission line that is owned by another Participating Transmission Owner. This modification would eliminate inconsistency and redundancy. DWR recommends modifications to Section 13 of the Transmission Control Agreement to conform language for Existing Agreements and Contracts. 702/

The Companies state that the Transmission Control Agreement is a contract that requires execution by the signatory parties. Therefore, the Companies claim that the August 15 Transmission

Control Agreement revisions cannot be unilaterally imposed and

699/ Id. at 33.

700/ The Companies note that the ISO s proposed revision is inconsistent with Transmission Control Agreement Section 2.2.1, which provides that a Party whose application has been accepted shall become a Participating Transmission Owner with effect from the date when its Transmission Owner Tariff takes effect.

701/ Companies at 3-4.

702/ DWR at 55.

should be viewed as ISO comments rather than revisions to the March 31 filing. 703/ The Companies do agree to all proposed revisions not specifically opposed.

The California Commission continues to be concerned with the staging of control of the transmission grid. 704/ According to the California Commission, the independence of the ISO from the Transmission Owners in controlling the grid is one of the paramount factors in successful implementation of retail competition in California. For example, the California Commission points out that the Companies' energy control centers will continue to perform many functions, which should be transferred to the ISO no later than the January 1, 2000 date indicated in the Staging Plan. The California Commission requests assurances that the reliance on energy control centers will not continue indefinitely. 705/

The California Commission argues that ISO staff, rather than employees of the Companies, should operate the functions performed by the energy control centers, to ensure the independence of the ISO from the Transmission Owners. Therefore, the California Commission requests that the ISO be authorized to place its own employees in any field position the ISO deems necessary for effective grid control, restrict transfers of employees from the ISO to the Transmission Owners, and give ISO personnel the authority to inspect any transmission facility or equipment any time without prior notice. 706/

The Companies oppose the proposed revision to Transmission Control Agreement Section 3.3.3, regarding the need for regulatory approval of withdrawal by the parties, including the ISO. The Companies assert that it is only the withdrawing party that should obtain any regulatory approval, subject to prior Commission approval of any transfer of control of jurisdictional facilities from the ISO. 707/

The California Commission opposes the revisions to Transmission Control Agreement section 4.1.3(ii), that would not allow the ISO to reject facilities where a Participating

703/ Companies at 2.

704/ August 15 Filing, Appendix II at 2.

705/ California Commission at 10.

706/ California Commission at 10-11.

707/ Companies at 4-5.

Transmission Owner cannot remove encumbrances. This would force the ISO to operate facilities that may be useless. 708/

M-S-R contends that when some but not all participants in a jointly-owned project turn over their rights in a project to the ISO, the ISO should not impinge on the rights of the project owners. M-S-R argues that the ISO s proposal to require the Participating Transmission Owner to have all of the rights and authority to place them into the ISO Operational Control fails to focus on the obligations a joint owner has to its co-owners. Instead, M-S-R recommends modification of Transmission Control Agreement Section 4.1.1 to allow the ISO to exercise Operational Control only to the extent that the Participating Transmission Owner could exercise control under the relevant project agreements. 709/

M-S-R recommends modification of Transmission Control Agreement Section 4.1.3 to clarify that lines and associated facilities located in a Control Area outside of California and are operated under the direction of another Control Area or ISO should not be placed under the Operational Control of the ISO. 710/

The Companies oppose the proposed revision to Transmission Control Agreement Section 4.1.5, regarding the statement that the Participating Transmission Owner must warrant that it has all of the necessary rights and authority to place transmission lines, associated facilities, and Entitlements under the ISO Operational Control. The Companies propose revisions indicating that (1) transmission lines and associated facilities to be placed under the ISO s Operational Control and the Participating Transmission Owner s Entitlements to be made available are correctly identified and (2) that the Participating Transmission Owner has the rights and authority to place such facilities under ISO Operational Control and to transfer such Entitlements. 711/

The Companies contend that the proposed revision to Transmission Control Agreement Section 4.7, regarding removal of facilities, fails to provide a mechanism for return of Operational Control of facilities to the Transmission Owner, where such facilities are either retired from service, or no

708/ California Commission at 32.

709/ M-S-R at 13-15.

710/ M-S-R at 16-17.

711/ Companies at 7.

longer classified as transmission, or are no longer needed for the ISO to fulfill its control area responsibilities. 712/

The Companies contend that the proposed revision to Transmission Control Agreement Section 5.1.1, regarding WSCC membership and issues to be decided by ADR are unnecessary, because these are already assured under ISO Tariff Sections 13.2.2, 13.2.4, and 13.3.11.1. 713/

The Companies support the intent of the proposed revision to Transmission Control Agreement Section 5.1.8, (regarding prevention of system emergencies, to clarify that the ISO has the responsibility to prevent emergencies rather than simply respond). The Companies recommend further refinements to require the ISO s actions and directions to be consistent with the duty of care provisions under Section 5.1.3. 714/

The California Commission opposes the revisions to Transmission Control Agreement section 5.2.3 that allow Participating Transmission Owners to install computerized Power Management Systems to monitor transmission facilities in the ISO Grid, as an inappropriate intrusion on ISO independence. The California Commission does not believe the ISO should have to separate the system on a Transmission Owner by Transmission Owner basis or design an integrated system, and is concerned that the ISO would have to implement procedures to ensure that Transmission Owners are not provided information related to other Transmission Owners. Also, the provision unfairly advantages Participating Transmission Owners, states the California Commission. 715/

The Companies oppose the proposed revision to Transmission Control Agreement Section 6.1.2, regarding operational orders affecting health and safety as confusing, and not providing additional clarity as claimed by the ISO. The Companies assert that under the agreement reached among the participants, the final responsibility for safety of personnel and the public remains with the Participating Transmission Owner and its employees, who perform the actual physical operation of the facilities. 716/

712/ Companies at 8.

713/ Companies at 9.

714/ Companies at 11.

715/ California Commission at 31-32.

716/ Companies at 12.

The Companies note a typographical error in Transmission Control Agreement Section 8.1.1, in which the term "ISO Controlled Grid Protective Systems" should read "ISO Controlled Grid Critical Protective Systems." 717/

The Companies oppose the inclusion of definitions in Transmission Control Agreement Appendix D that refer to items in the ISO tariff that are not reflected in the Transmission Control Agreement. 718/

SDG&E proposes revisions to the Encumbrance included in the March 31 filing, to address concerns raised in discussions with representatives of the Internal Revenue Service (IRS) that a disqualifying use of facilities financed with Local Furnishing Bonds may arise if the Commission ultimately approves a uniform regional transmission charge. SDG&E states that as currently drafted, the Encumbrance pertaining to Local Furnishing Bonds does not specify whether the Commission's acceptance of a uniform regional rate would trigger the filing of a section 211 application, an order to ensure that interest on Local Furnishing Bonds that continue to be utilized in a qualifying fashion will remain tax-exempt. SDG&E recommends revisions providing that, if bond counsel or the IRS cannot be persuaded that a uniform rate does not adversely affect the tax-exempt status of interest on Local Furnishing Bonds, then the process adopted by the Commission in Order No. 888 would be used to protect the tax-free status of interest on bonds that have been utilized to finance facilities continuing to be used in a qualifying fashion. Moreover, SDG&E would not object to the ISO seeking an order under section 211 of the FPA with respect to service under uniform regional rate terms. 719/

Commission Response

We agree with Southern Cities/Azusa and Banning that certain provisions could benefit from additional clarifications and we accept the recommended changes to Section 2.1.2., 3.1, 4.6.1, 5.1.1, 5.1.7, 5.1.9. 5.2.3, 14.3.2 and 22.1. 720/ These clarifications/corrections are ministerial and no further explanation is needed. Their other substantive changes are discussed below.

717/ Companies at 13.

718/ Companies at 14.

719/ SDG&E at 1-3.

720/ Southern Cities/Azusa and Banning September 2, 1997 Comments at 32-34.

We reject the California Commission's proposed modification to Section 6.1.1 of the Transmission Control Agreement. We do not believe that the ISO should now have the added responsibility of physically, as well as operationally, operating the facilities that make up the ISO Controlled Grid. We find that the ISO does not now possess the personnel and experience to physically operate the lines and facilities that constitute the ISO Controlled Grid. Moreover, the Commission is concerned that imposing such a requirement upon the ISO at this time will unnecessarily burden the ISO's initial start-up phase. In addition, we reject the California Commission's recommendation that the ISO be able to assign maintenance of a Participating Transmission Owner's facilities to a third party. We anticipate that the maintenance standards adopted in Appendix C to the Transmission Control Agreement and the incentives and penalties ultimately adopted pursuant to Section 9 of Appendix C will ensure that each Participating Transmission Owner adequately maintains its facilities.

We agree with the California Commission that the ISO must be independent from the Transmission Owners. We agree that the ISO should have operational control over the facilities that constitute the ISO Controlled Grid. However, we realize that for an interim period it may be necessary for the ISO to rely on the Companies' energy control centers as indicated. With regard to the California Commission's recommendation that ISO employees staff the Companies' energy control centers and certain field positions, we find that this recommendation to be inconsistent with our position that, at least initially, the Companies maintain hands-on control of their systems. As previously noted, the details of the transfer of these facilities have not been finalized and will be the subject of another section 203 filing. This submittal should be filed prior to the ISO Grid Operation Date.

We reject the California Commission's recommendation that the Transmission Control Agreement be made a part of the ISO Tariff. We find that there is a necessary distinction between the rights and obligations of parties under the ISO Tariff and the rights and obligations of parties under the Transmission Control Agreement. The ISO Tariff appropriately establishes the rates, terms, and conditions of transmission and other related services over the ISO Controlled Grid. The Transmission Control Agreement establishes the rights, obligations, and extent of ISO operational control over the physical facilities that have been transferred to the ISO and rights of the ISO to utilize certain Entitlements. We find that the Transmission Control Agreement generally does not contain provisions that would apply generally to all ISO Controlled Grid users and therefore does not belong as part of the ISO Tariff. We reject LADWP's requests that the non-rate terms and conditions set forth in the Transmission Owner Tariff be transferred to the ISO Tariff.

We accept DWR's proposed clarification to Section 2.2.5 to indicate that non-public utilities are not required to file Transmission Owner Tariffs with the Commission. However, we encourage such entities to post such Tariffs and especially all transmission rates on the ISO's electronic bulletin board (WEnet). We direct the ISO to provide all necessary arrangements to accommodate such postings.

We reject NCPA's argument that the Companies should be required to again separately apply to the ISO for their transmission facilities to be included. The facilities over which the Companies propose to turn operational control to the ISO have been reviewed by the ISO and are the subject of a section 203 filing. Moreover, the Transmission Control Agreement is a joint agreement between the ISO and any Participating Transmission Owner and the Companies have voluntarily agreed to become parties to the agreement.

We agree with LADWP that the rate, terms and conditions of service under a non-public utility's Transmission Owner's Tariff is not subject to our jurisdiction under sections 205 and 206. However, the individual Transmission Owner Tariff filed by the Companies appropriately recognizes Commission jurisdiction over their rates, terms and conditions of service. Naturally, to the extent a non-public utility files a Transmission Owner Tariff with its regulatory body, that tariff would likewise recognize that the rates, terms and conditions of service of the tariff are subject to the approval of that regulatory body. Accordingly, Sections 7.2.3, 8.1.3 and 12 of the Transmission Owner Tariff need clarification to delineate the Commission's jurisdiction.

Section 2 - Participation In This Agreement

We agree with Southern Cities/Azusa and Banning that Section 2.2.3 should be revised to provide that a Transmission Owner can become a Participating Transmission Owner while objections under Section 4.1.3 of the Transmission Control Agreement are resolved. Conversely, we reject the California Commission's argument. We believe that an entity can become a Participating Transmission Owner pending the outcome of an ADR procedure regarding eligibility.

We reject Southern Cities/Azusa and Banning's recommended changes to the comment periods and the service of applications provided for in Section 2.2.2 of the Transmission Control Agreement. The ISO/PX's proposed comment period is reasonable. We also reject Southern Cities/Azusa and Banning's argument that the types of processing costs under Section 2.2.6 of the Transmission Control Agreement should be defined. However, we direct the ISO to add a sentence to Section 2.2.6 to provide that the ISO will furnish Applicants, upon request, an itemized bill for the costs of processing their application.

Tax-exempt Status

The ISO/PX propose numerous provisions in the ISO Tariff that are intended to protect the tax-exempt status for Local Furnishing Bonds and municipal debt. The ISO/PX state that until the affected parties secure a ruling from the Internal Revenue Service that participation in the ISO will not affect their tax-exempt status, the ISO/PX will not require any Party to take any action which may cause it to lose its tax-exempt status.

SDG&E proposes modifications to the Encumbrances set forth in Original Sheets Nos. 76, 77, 78, and 79 of the Transmission Control Agreement filed on March 31, 1997. 721/ Under the procedures proposed by SDG&E, if the ISO proposes: 1) that SDG&E take, or refrain from taking, any action that SDG&E believes will jeopardize the tax-exempt status of interest on its Local Furnishing Bonds; or 2) a rate for the use of SDG&E's transmission facilities that is in whole or in part based on the costs to other Participating Transmission Owners, the ISO will either not require SDG&E to take (or refrain from taking) the specified action or will return operational control of SDG&E's facilities to SDG&E unless SDG&E has secured an unqualified opinion from bond counsel that the proposed action (inaction) or ratemaking will not affect the tax-exempt status of the interest on Local Furnishing Bonds issued for SDG&E. If SDG&E has been unable to obtain the unqualified opinion of bond counsel, upon written request from the ISO, SDG&E in good faith shall promptly seek to obtain a ruling from the IRS that the requested action (or inaction) or transmission rate will not adversely affect the tax-exempt status of interest on its Local Furnishing Bonds. If SDG&E cannot obtain such a ruling, SDG&E will not object to the ISO seeking an order under Section 211 of the FPA with respect to the requested action or ISO transmission rate proposal. 722/

In reply, the ISO/PX has no objection to SDG&E's proposed Encumbrance amendment, which resulted from discussions between SDG&E and the Internal Revenue Service. 723/

We will accept SDG&E's proposed modifications with the clarification that any actions taken to address a potential loss of the tax-exempt status of Local Furnishing Bonds are consistent with the procedures we adopted in Order Nos. 888 and 888-A with regard to maintaining the tax-exempt status of Local Furnishing

721/ September 2, 1997, Comments of SDG&E at 2-3 and Exhibit A.

722/ Id.

723/ September 16, 1997, Comments of ISO/PX at 16-17.

Bonds. 724/ In addition, with regard to SDG&E's proposal that it will not object to the ISO seeking an order under section 211 of the FPA, we note that the ISO in and of itself, is not eligible to file a section 211 application. 725/ We direct SDG&E to

revise its proposal accordingly to provide that SDG&E will not object to the ISO, acting as agent for an entity eligible to file a section 211 application seeking an order under section 211.

A number of intervenors raise concerns with regard to the potential loss of tax-exempt status for interest on their municipal debt if they participate in the ISO. 726/ LADWP requests that the Commission order the addition of language in the ISO Tariff which would specifically preserve the tax-exempt status of municipal debt. LADWP states that the Commission similarly ordered that language be added to the ISO documents in Wisconsin Electric Company, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin) and Cenergy, Inc.,(Primergy). 727/ The ISO/PX state that it has no objection to such a request and will work with LADWP to fashion appropriate language. 728/ We agree with LADWP's proposal. Therefore, we direct the ISO/PX to propose suitable language in its compliance filing that will address, to the extent possible, the concerns raised by LADWP, TANC, NCPA, Modesto, and CMUA.

Section 3 - Effective Date, Term and Withdrawal

Section 3 of the Transmission Control Agreement provides that a Party may apply to withdraw from the Transmission Control Agreement on two-years' notice subject to obtaining all necessary regulatory approvals. Western contends that Transmission Control Agreement Section 3.3 should be amended to give the parties to

724/ See Pro Forma Open Access Transmission Tariff, Section 5.2. We expect that any other future member of the ISO with Local Furnishing Bonds similarly follow the Order Nos. 888 and 888-A Local Furnishing Bond procedures.

725/ Entities eligible to file a section 211 application are "[a]ny elect utility, Federal power marketing agency, or any other person generat electric energy for sale for resale" 16 U.S.C. □ 824; (a)(1994).

726/ See, e.g.,September 2, 1997, Comments of LADWP at 32-33; TANC at 9-1

727/ 79 FERC □ 61,158 at 61,737 (1997).

728/ September 16, 1997, Comments of ISO/PX at 17.

the Transmission Control Agreement the unilateral right to withdraw subject only to a reasonable notice period. 729/ We find Western's proposed modification to be unreasonable and unsupported. Western's proposal does not address or require the withdrawing party to first satisfy applicable NERC and WSCC requirements for operating a control area or being included in an existing control area.

Section 4 - Transfer of Operational Control

We agree with M-S-R that when some, but not all, participants in a jointly-owned facility turn over their rights to the ISO, the ISO s use of those rights should not adversely impact the rights of those parties that did not transfer their rights to the ISO. We direct the ISO to include in Section 4.1.1 of the Transmission Control Agreement a provision which recognizes the rights, obligations and extent of operational control of the ISO and the owners of any jointly-owned facility. While the ISO can obtain only that control which the co-owner has to give it, we encourage all co-owners to transfer their rights and participate in the ISO.

Turlock and Western object to the inclusion of facilities under the ISO control which only marginally impact grid reliability. We find the proposed modification to the Transmission Control Agreement unreasonable. As proposed, the Transmission Control Agreement requires that the transmission network must be under the ISO's operational control. We see no reason to introduce a further qualification that requires only those network facilities that materially affect the overall operation and reliability of the system to be under the ISO's control.

LADWP contends that Section 4.1.1 of the Transmission Control Agreement, which provides that the ISO can reject transmission facilities "not necessary to fulfill the ISO's responsibilities", is inconsistent with Section 4.1.3 of the Transmission Control Agreement and the Commission's ISO Principles. 730/ LADWP argues that Section 4.1.1 of the Transmission Control Agreement is inconsistent with the Commission's ISO Principles 3 and 5 which provide that an ISO should create the largest ISO-controlled grid as possible and subject all transmission facilities within the ISO-controlled grid to ISO control. NCPA also states that the ISO should not be able to reject transmission facilities. 731/ LADWP states that Section 4.1.3 of the Transmission Control Agreement allows the ISO to reject transmission facilities because the ISO cannot: 1) operate the lines in accordance with Applicable Reliability Criteria or 2) operate the lines in accordance with the ISO Tariff. LADWP contends that the standard for rejection under Section 4.1.1 of the Transmission Control Agreement is different than the standards under Section 4.1.3 of the Transmission Control Agreement. We disagree. Section 4.1.1 of

729/ Western at 84.

730/ September 2, 1997, Comments of LADWP at 41-42.

731/ September 2, 1997, Comments of NCPA at 25-26.

the Transmission Control Agreement specifically states that facilities will be rejected from inclusion in the ISO in accordance with Section 4.1.3 of the Transmission Control Agreement. We find that no modification of Section 4.1.1 of the Transmission Control Agreement is required.

We reject in part, and accept in part, M-S-R s recommendation that Section 4.1.3 of the Transmission Control Agreement provide that transmission facilities located in another control area (outside of California) should not be placed under the Operational Control of the ISO. To the extent an entity located outside of California or in another control area wishes to turn operational control of its facilities over to the ISO, and thereby be included in the ISO Controlled Grid, that entity should be permitted to do so. This is

consistent with ISO Principle Nos. 3 and 5, that the ISO should cover as large a geographic region as possible. However, to the extent the ISO cannot feasibly operate facilities located in another control area, the ISO must be able to reject those facilities and prohibit them from inclusion in the ISO Controlled Grid. Therefore, we direct the ISO to add a Section 4.1.3(iii) that reads as follows:

> Lines and associated facilities that are located in a Control Area outside of California and are operated under the direction of another Control Area or independent system operator and that cannot be integrated into the ISO Controlled Grid due to technical considerations cannot be included in the ISO Controlled Grid.

We agree with LADWP that a Participating Transmission Owner should be required to negotiate the removal of any Encumbrance (e.g., inability to utilize unused capacity under an existing contract) that would inhibit or prohibit the ISO from exercising operational control over certain facilities or entitlements. We also agree that if renegotiation of an existing contract is not successful, the ISO should have the discretion to elect not to include that facility in the ISO Controlled Grid. In this event, the provisions of the existing contract will be maintained. 732/ However, we find that the ISO/PX's proposed modification to Section 4.1.3 of the Transmission Control Agreement accomplishes the desired objective. Therefore, we find that no further modifications are necessary.

We also agree with LADWP that the ISO's rejection of facilities could lead to the undesired creation of a patchwork transmission system operated in part by the ISO and in part by Transmission Owners. 733/ We agree that the

732/ September 2, 1997, Comments of LADWP at 44-47. Contrary to LADWP's our reading of the revised language, we note that the California Commission erroneously interprets the revised Transmission Control Agreement language such that the ISO cannot reject the facilities. September 2, 1997, Comments of the California Commission at p. 32.

733/ September 2, 1997, Comments of LADWP at 51-52.

ISO should never reject facilities only on an economic basis. 734/ We encourage the development of a regional ISO. However, we believe that the ISO must have the unfettered ability to screen the transmission facilities over which it assumes operational control in order to prevent the ISO from operating a facility that in any way impairs the reliability or operation of the system.

With regard to LADWP's and TANC's concern over the use of the ISO ADR procedures to resolve disputes, we agree with LADWP that Non-Participating Transmission Owners should be able to utilize the ISO ADR procedures on a voluntary basis and otherwise should not be bound by the ISO ADR procedures. We direct the ISO/PX to add language to Section 4.1.3.(ii) to reflect this. In addition, we agree with TANC that disputes arising under existing contracts should be resolved under the dispute resolution procedures of that contract. 735/

We agree with the Companies' proposed revisions to Section 4.1.5 of the Transmission Control Agreement. 736/ Section 4.1.5 of the Transmission Control Agreement should be revised to distinguish between the ISO's ability to control the operation of facilities and the ISO's right to utilize Entitlements.

We reject LADWP's, TANC's, NCPA's, and CMUA's argument that a Participating Transmission Owner should have the unencumbered right to sell or dispose of its facilities or Entitlements subject only to notifying the ISO. 737/ For the reasons stated by the ISO/PX, we reject the test proposed by LADWP. We accept the Transmission Control Agreement Section 4.4 provision requiring ISO approval for any transfer of facilities. We feel that this requirement provides a necessary safeguard to ensure the continued operation of the ISO Controlled Grid and the corresponding provision of transmission service.

The ISO's proposal in Section 4.5.2 of the Transmission Control Agreement allowing it to assume temporary control over facilities either to obtain operational experience or pending the resolution of a dispute is reasonable. We do not believe that LADWP's proposal to compensate Participating Transmission Owners for the temporary use of such facilities is practical or necessary. The costs of any such facility temporarily controlled by the ISO will already have been assigned and recovered under a non-ISO service arrangement. We also note that any charge to the ISO for temporary use would be primarily recoverable by the ISO from the load served by the

734/ September 2, 1997, Comments of LADWP at 52-54.

735/ September 2, 1997, Comments of TANC a 36-38.

736/ September 2, 1997, Comments of Companies at 6-7.

737/ June 6, 1997, Comments of LADWP at 52-54; TANC at 101-103; NCPA at 3 and CMUA at 29.

Participating Transmission Owner's transmission facilities. Therefore, essentially the same customers would pay the costs associated with those facilities, either under the ISO Tariff or under the Participating Transmission Owners other arrangements. We also note such compensation between the ISO and a public utility will require a Section 205 filing.

In addition, we disagree with Southern Cities/Azusa and Banning that Section 4.5.2 of the Transmission Control Agreement should be modified in order to limit the number of times in a given period that the ISO can assert operational control over specific facilities. 738/ The ISO must have the flexibility to assert operational control over facilities when, in its best judgment, its needs control those facilities in order to fulfill its control area responsibilities. We believe that imposing an arbitrary limit on the number of times the ISO can assert control over facilities will unnecessarily restrict the ISO's operations and may endanger reliability.

The Companies and Metropolitan contend that the Transmission Control Agreement should provide that the ISO has the right to return facilities that the ISO no longer requires. We agree. The ISO Controlled Grid could be reconfigured in the future and the ISO may no longer need to control certain

facilities in order to fulfill its Control Area responsibilities. We direct the ISO to propose language in Section 4 that will accommodate the return of temporary operational control from the ISO to the relevant Participating Transmission Owners. As discussed above, the ISO must record when such a transfer of control occurs.

Section 5 - Independent System Operator

LADWP, Southern Cities/Azusa and Banning and the Companies support the intent of Section 5.1.1 of the Transmission Control Agreement (i.e., no party to a dispute should take a position before the WSCC or the relevant RTG that is inconsistent with an ADR Procedure decision). We believe that this provision is appropriate. Contrary to Western's assertions, we do not believe that Section 5.1.1 is an impediment to open and free discussion. All parties that receive adequate notice of the dispute resolution procedures and decision should be bound by the ADR decision. However, we agree with LADWP, Southern Cities/Azusa and Banning and the Companies that the ISO/PX's language implementing this provision is unclear. Therefore, we direct the ISO to revise Section 5.1.1 as proposed by the Companies. 739/

We agree with Southern Cities/Azusa and Banning and the Companies that Section 5.1.8 of the Transmission Control Agreement needs clarification. We direct the ISO/PX to conform Section 5.1.8 of the Transmission Control Agreement to read as proposed by the Companies:

738/ September 2, 1997, Comments of Southern Cities/ Azusa and Banning at

739/ September 2, 1997, Comments of Companies at 10. We note that by adopting the Companies' revisions, NCPA's concerns are also addresse

> In the event of a System Emergency, the ISO shall have the authority and responsibility to take all actions necessary and shall direct the restoration of the ISO Controlled Grid to service following any interruption associated with a System Emergency. The ISO shall also have the authority and responsibility, consistent with Section 4 and Section 9, to act to prevent System Emergencies. Actions and directions by the ISO pursuant to this Section 5.1.8 shall be consistent with Section 5.1.3, Duty of Care.

We find that Southern Cities/Azusa and Banning's recommended changes to Sections 5.1.6, 6.4.1, 17.4.1 and 17.4.2 to be unnecessary.

We agree with Southern Cities/Azusa and Banning that Section 5.1.3 of the Transmission Control Agreement should be modified to reflect the fact that the ISO's operating practices are subject to encumbrances from Existing Contracts. As suggested by Southern Cities/Azusa and Banning, the third sentence of Section 5.1.3 of the Transmission Control Agreement should read:

> It shall act in accordance with Good Utility Practice, applicable law, Existing Contracts, the ISO Tariff and the Operating Procedures.

We disagree with the California Commission's position that Section 5.2.3

of the Transmission Control Agreement, which allows Participating Transmission Owners to install their own Power Management Systems to monitor transmission facilities on the ISO Controlled Grid, is an intrusion on the ISO's independence. We find that, in fact, the provision may provide for the creation of a redundant monitoring system that may improve the reliability of the facilities which they own. We note that a Participating Transmission Owner's monitoring system would be used to monitor its own facilities, not the facilities of another Transmission Owner.

Section 6 - Participating Transmission Owners

We agree with the Companies that Section 6.1.2 of the Transmission Control Agreement (regarding ISO Operating Orders) needs clarification. We interpret the first sentence of Section 6.1.2 to mean that a Participating Transmission Owner will follow all orders of the ISO, including any orders that may result in the risk of damage to facilities. We also agree with the ISO/PX that the section should contain a notification provision. Therefore, we find that Section 6.1.2 should read as follows:

> 6.1.2 ISO Operating Orders. Each Participating Transmission Owner shall operate its transmission facilities in compliance with ISO Protocols, the Operating Procedures (including emergency procedures in the event of communications failure) and the ISO's operating orders unless the health or safety of personnel or the general public would

> be endangered. Proper implementation of an ISO operating order by a Participating Transmission Owner shall be deemed prudent. In the event an ISO order would risk damage to facilities, and if time permits, a Participating TO shall inform the ISO of any such risk and shall seek confirmation of the relevant ISO order.

We disagree with Southern Cities/Azusa and Banning's suggested modification to Section 6.2.1 of the Transmission Control Agreement. We agree with the California Commission and find that the ISO should have access to facilities that may impact the reliability of the ISO Controlled Grid, including those not currently under its operational control. We agree that to the extent the ISO requires access to the facilities of a Participating Transmission Owner, such access should only be permitted under the terms of the ISO and Transmission Owner Tariff. On a related issue, we agree with TANC that the ISO should give reasonable notice of access and coordinate the installation of facilities on property owned by the host utility. We direct the ISO to revise Section 18.1 of the Transmission Control Agreement accordingly.

Section 7 and Appendix C - System Operation and Maintenance and Maintenance Standards

We agree with Southern Cities/Azusa and Banning's proposed changes to Section 7.1 of Appendix C to the Transmission Control Agreement. Moreover, in light of the importance placed on maintenance practices under the

Restructuring Legislation and this Commission's continued emphasis on maintaining the reliability of the interconnected grid, we direct the ISO to add a section under Article IV of the ISO's Bylaws to provide for the permanent creation of an advisory Maintenance Coordination Committee that will perform the duties specified under Section 7 of the Transmission Control Agreement. Therefore, we reject the California Commission's recommendation that maintenance standards be changed through recommendations of the Technical Advisory Committee.

Section 8 - Auxiliary Equipment and ISO Controlled Grid Critical Protective Systems

We agree with the Companies' proposed correction to Section 8.1.1 of the Transmission Control Agreement. 740/ The Companies' proposed correction is consistent with the definitions in the Master Definitions Supplement of the Transmission Control Agreement. In addition, we agree with the Companies that the Master Definitions Supplement appended to the ISO Tariff and the Transmission Control Agreement should be conformed to include only those terms used in each of the documents. We also agree that all section references in

740/ The correction inserts the word "critical" in front of Protective Systems. September 2, 1997, Comments of Companies at 12-13.

either the ISO Tariff, the Transmission Control Agreement, or any other ISO or PX document must include the name of the relevant document. 741/ We order the ISO and PX each to make conforming changes on compliance.

Section 9 - System Emergencies

Consistent with our discussion of Section 6.1.2 of the Transmission Control Agreement above, we reject LADWP's recommendation that a Participating Transmission Owner should have the right not to follow the ISO's orders if it believes those orders are likely to cause serious damage or destruction to its facilities. In an emergency, the ISO needs to be certain that its operating instructions will be followed. 742/ In addition, we note that the ISO will be financially responsible for any damage caused to transmission facilities if it acts negligently in issuing operating instructions. 743/

Section 10 -ISO Controlled Grid Access and Interconnection

We reject NCPA's suggested changes to Section 10.2.3 (System Upgrades) of the Transmission Control Agreement. 744/ NCPA's change would require an entity requesting an Interconnection to not only pay for all system reliability upgrades on its side of the Interconnection, but also require the entity to maintain existing interconnection profiles. NCPA has not adequately explained the basis and justification for its proposed modifications. NCPA's modification does not appear to be related to reliability and may create a barrier to entry. In addition, we find that the purpose of TANC's suggested modification to Section 10.2.3 of the Transmission Control Agreement to be

unclear. 745/ TANC's modification simply states that an entity will not be required to execute an Interconnection Agreement that does not allow adequate use of the ISO Controlled Grid. If an entity believes that a Participating Transmission Owner is attempting to erect barriers to entry to the ISO Controlled Grid by imposing unreasonable requirements under an Interconnection Agreement, such entity can utilize the ISO's ADR Procedure in order to resolve the dispute. To the extent the ISO's ADR

741/ Id. at 13-14.

742/ LADWP at 58-59.

743/ Transmission Control Agreement Section 22.1.

744/ September 2, 1997, Comments of NCPA, Appendix A at 28.

745/ September 2, 1997, Comments of TANC, Revised Appendix A at 58.

Procedure produces a result unacceptable to that party, that party can always appeal the arbiters' decision to the Commission.

We disagree with the California Commission's statement that Section 10.3 of the Transmission Control Agreement inappropriately gives the Participating Transmission Owners the responsibility of developing interconnection standards. Participating Transmission Owners have detailed knowledge of their systems and are the most qualified entities to develop the technical standards for the interconnection of load and/or generation to their facilities. Moreover, Section 10.3 already provides that the Participating Transmission Owners will develop such standards in consultation with the ISO. However, we agree with DWR that Section 10.3.1 should be modified to state that the owner, as opposed to Entitlement holder, of a particular transmission facility should be responsible for developing the technical standards for interconnecting with that facility.

Section 12 - Use and Administration of the ISO Controlled Grid

We disagree with the California Commission's criticism of Section 12.3 of the Transmission Control Agreement. We believe that this section appropriately allows the ISO to consult with Participating Transmission Owners in the development of standards and collection mechanisms for incentives and penalties pertaining to use of the ISO Controlled Grid. The ISO, in consultation with other stakeholders, has successfully resolved and implemented numerous issues to date. We have no reason to believe that the ISO will be any less successful in resolving such issues in the future.

Section 13 - Existing Agreements

We reject DWR's suggestion to modify Section 13 of the Transmission Control Agreement to address Existing Contracts. DWR did not recommend specific tariff language and the Commission finds DWR's recommendation unnecessary.

Section 16 - Billing and Payment

We agree with Southern Cities/Azusa and Banning that Section 16 of the Transmission Control Agreement should be revised. The second sentence of Section 16 of the Transmission Control Agreement should read as follows:

> In addition, the Participating Transmission Owner shall pay all appropriate charges, including any charges that arise under the Self-Sufficiency test provisions of the [Transmission Owner] Tariff.

Section 26 - Miscellaneous

We reject, in part, LADWP's revision to Section 26.11 of the Transmission Control Agreement. We require that the Transmission Control Agreement clearly provide that the agreement can be amended by order of the Commission. Section 26.11 should read as follows:

> This Agreement may be modified: (1) by mutual agreement of the Parties, subject to approval by FERC; (2) through the ISO ADR Procedure set forth in Section 13 of the ISO Tariff; or (3) upon issuance of an order by FERC.

We disagree with Southern Cities/Azusa and Banning that Section 26.4 of the Transmission Control Agreement should be deleted. 746/ While we recognize that the ISO was created to foster competition and thereby benefit all electricity customers that require its use, we find that Southern Cities/Azusa and Banning's interpretation to be too narrow. The parties to the Transmission Control Agreement are entitled to preclude other non-party entities from asserting third-party beneficiary status upon themselves.

The Commission Orders:

(A) The untimely motions to intervene in this proceeding are hereby granted.

(B) The motions to file additional comments in this proceeding are hereby granted.

(C) The motions to strike comments are hereby denied.

(D) The ISO and PX are hereby conditionally granted interim authorization to commence limited initial operations on November 1, 1997, as discussed in the body of this order.

(E) The ISO and PX are hereby conditionally granted interim authorization to commence full operations on the ISO Operations Date, as discussed in the body of this order.

(F) The Companies are hereby conditionally granted interim authorization pursuant to section 203 of the FPA for the transfer of operational control of the Companies transmission systems to the ISO, effective on the ISO Operations Date.

746/ Section 26.4 Third Party Beneficiaries states that:

> The Parties do not intend to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreemen of any duty, covenant, obligation, or undertaking established hereunder.

(G) The ISO/PX's filing of March 31, 1997, as amended by its filing of August 15, 1997, is hereby accepted for filing, as modified by this order, to become effective on the ISO Operations Date.

(H) The ISO and PX compliance staff are hereby directed to conduct studies and file reports, as discussed in the body of this order and Appendix C.

(I) The Commission hereby accepts the ISO and PX proposed plan for filing protocols and procedures, subject to the qualifications and conditions discussed herein. The PX is directed to file its proposed Activity Rules under section 205 of the FPA.

(J) The Companies are hereby conditionally granted interim authorization to sell electric energy at market-based rates through a power exchange, subject to the mitigation measures and monitoring requirements discussed in the body of this order.

(K) The Chief Executive Officers of SoCal Edison, PG&E, SDG&E, the ISO, and the PX are each hereby directed to certify to the Commission, prior to the date that ISO and PX operations commence, that all of the necessary features are in place to ensure reliable grid operations, and pre-operational testing will be performed, as discussed in the body of this order.

(L) The ISO and PX are hereby directed to make all future filings separately with respect to their individual Tariffs and all related agreements, as discussed in the body of this order.

(M) The ISO's and PX's request to delay the filing of a compliance filing until after they become operational is hereby granted.

(N) The ISO and PX shall each promptly post on WEnet their respective Tariffs and related appendices and agreements, that will become effective upon initiation of service, as modified by this order.

(O) The PX and the ISO are hereby directed to make information publicly available, as discussed in the body of this order.

(P) The requests for rehearing of the July 30 Order regarding requests for hearings and other procedures are hereby denied, as discussed in the body of this order.

(Q) The requests for reconsideration of the November 26 Order's rulings regarding the California residency requirement and the limitation of responsibilities of the California Oversight Board are hereby denied, as discussed in the body of this order.

(R) Other requests for rehearing of the November 30 Order, the December 18 Order, and the July 30 Order are hereby granted or denied, except as otherwise noted in the body of this order.

(S) PG&E, SoCal Edison, and SDG&E, are hereby directed to amend their existing open access Tariffs, as discussed in the body of this order.

(T) The ISO/PX's request to delay the August 15, 1997 filing deadline for various subsidiary Agreements is hereby conditionally granted, as discussed in the body of this order.

(U) At least 60 days prior to imposing any penalties, the ISO and PX shall each file the proposed penalties and the behavior that would trigger them pursuant to section 205 of the FPA, as discussed in the body of this order.

(V) The ISO is hereby directed to file its Must-Run unit selection, including the rationale and criteria used in the selection, in time for acceptance prior to the ISO Operations Date.

By the Commission.

(S E A L)

Lois D. Cashell,
Secretary.