SWIDLER BERLIN SHEREFF FRIEDMAN, LLP

THE WASHINGTON HARBOUR
3000 K STREET, NW, SUITE 300
WASHINGTON, DC 20007-5116
TELEPHONE (202) 424-7500
FACSIMILE
WWW.SWIDLAW.COM

JULIA MOORE
DIRECT DIAL: (202) 295-8357
FAX: (202) 424-7643
JULIAMOORE@SWIDLAW.COM

NEW YORK OFFICE
THE CHRYSLER BUILDING
405 LEXINGTON AVENUE
NEW YORK, NY 10174
TEL.(212) 973-0111
FAX (212) 891-9598

November 25, 2002

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *California Independent System Operator Corporation*
Docket No. ER03-219-000
Transmission Control Agreement, Rate Schedule No. 7

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, the California Independent System Operator Corporation ("ISO"), on behalf of itself, Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("Edison"), and the Cities of Anaheim, Azusa, Banning, Riverside, and Vernon, California, respectfully submits for filing an amendment to the Transmission Control Agreement ("TCA") among the ISO and Participating Transmission Owners ("Participating TOs").[1] The current Participating TOs are Edison, PG&E, and SDG&E ("Original Participating TOs") and the City of Vernon ("Vernon").

The revisions being filed today are made in order to accomplish the following objectives:

1. To identify the transmission interests that the Cities of Anaheim, Azusa, Banning, and Riverside, California (the "Southern Cities"), which have applied to become Participating TOs, will be turning over to the ISO's

[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, Appendix A to the ISO Tariff.

Operational Control, as well as the Encumbrances on those transmission interests, by including those interests and Encumbrances in new Appendices A and B to the TCA;

2. To permit a tax-exempt Participating TO to withdraw its transmission facilities and Entitlements from ISO Operational Control upon the occurrence of an actual or impending adverse tax action by the Internal Revenue Service that jeopardizes the tax exempt status of bonds used to finance the acquisition of its facilities or Entitlements, in order to address concerns raised by the Southern Cities related to preservation of the tax-exempt status of their financing of certain of their transmission interests, by adding new Section 3.4 to the TCA and associated new definitions to Appendix D of the TCA;[2]

3. To address an issue raised by the Southern Cities regarding the need for assurance that the ISO would not unreasonably withhold consent to a sale, assignment, release, or transfer of an Entitlement, by revising Section 4.4.2 of the TCA;

4. To add a more detailed procedure for updating the ISO Register upon changes in the transmission interests under the ISO's Operational Control and to specify that the ISO Register is no longer to be made publicly available due to security issues, by revising Section 4.2 of the TCA;

5. To conform the Interconnection provisions of the TCA to the Interconnection provisions of ISO Tariff Amendment No. 39 recently accepted by the Commission, and to clarify the obligations of a Participating TO with regard to a request for Interconnection to a transmission facility for which the Participating TO does not have legal authority to compel Interconnection, by revising Section 10 of the TCA;

6. To delete obsolete references to the ISO Grid Operations Committee and to capitalize the defined terms "Operational Control" and "Entitlement" where that capitalization had been overlooked previously, by revising various provisions of the TCA;

7. To reflect a revised procedure between PG&E and the ISO for addressing compliance with transmission reliability standards, by revising the Supplement to PG&E's Appendix A of the TCA, and to update PG&E's Appendix B of the TCA to reflect changes in its Encumbrances and add a

---

[2] It should be noted that SDG&E already has the ability to choose not to follow ISO instructions if SDG&E believes that such action might jeopardize the tax-exempt status of their Local Furnishing Bonds. TCA, SDG&E Appendix B.I. Proposed new TCA Section 3.4 is merely establishing a process for withdrawal if an adverse tax action is anticipated or exists.

portion of Exhibit B-1 that had been omitted from the previous Order No. 614 compliance filing of the TCA;

8. To reflect changes in Edison's Entitlements and Encumbrances by updating Edison's Appendices A and B of the TCA;

9. To reflect changes in Vernon's Entitlements and Encumbrances by updating Vernon's Appendices A and B of the TCA;

10. To reflect changes in the requirements for off-site power supply for PG&E's and Edison's nuclear generating facilities by updating Appendix E of the TCA; and

11. To identify the persons to contact at each party for notice purposes by revising and expanding Appendix F of the TCA.

I. BACKGROUND

A. The Initial TCA Filings

The TCA is the agreement among the ISO and Participating TOs that establishes the terms and conditions under which Transmission Owners place certain transmission facilities and Entitlements under the ISO's Operational Control, thereby becoming Participating TOs. The TCA describes how the ISO and each Participating TO will discharge its respective duties and responsibilities with respect to the operation of those facilities and Entitlements. The initial TCA was filed as part of the comprehensive "Phase II" filings submitted by the trustee on behalf of the ISO on March 31, 1997. Refinements to the TCA were made as a result of an ongoing stakeholder process, and a revised TCA was submitted on August 15, 1997, in compliance with the Commission's order in *Pacific Gas and Electric Company, et al.*, 80 FERC ¶ 61,128 (1997). In its order dated October 30, 1997, the Commission granted interim and conditional authorization to the ISO to commence operations and required certain modifications to the TCA. *Pacific Gas and Electric Company, et al.*, 81 FERC ¶ 61,122. The ISO filed the revised TCA on February 20, 1998. By order dated March 30, 1998, *California Independent System Operator Corporation*, 82 FERC ¶ 61,325, the Commission conditionally accepted the TCA for filing to become effective on the ISO Operations Date and required further modifications to be made in a compliance filing within 60 days of the ISO Operations Date.[3]

[3] March 30, 1998 Order, 82 FERC at 62,276-79. The ISO made the Compliance filing on June 1, 1998. The Commission has not yet acted on the compliance filing. On February 11, 1999 as amended on April 19, 1999, the ISO filed a supplement to the TCA consisting of operating instructions and curtailment priorities for Path 15. The Commission accepted these submissions by order dated June 17, 1999 in Docket No. ER99-1770-000. *California Independent System Operator Corporation*, 87 FERC ¶ 61,312 (1999), *reh'g pending*.

B. The TCA Filings to Add Vernon as a New Participating TO

On December 21, 2000, the ISO filed with the Commission an amended version of the TCA intended to accommodate Vernon's application to become a New Participating TO. That amended TCA was executed by the ISO, the Original Participating TOs, and Vernon. By order dated February 21, 2001, *California Independent System Operator Corp., et al.*, 94 FERC ¶ 61,141, the Commission accepted the amended TCA and granted waiver of the notice requirement so that the amended TCA was made effective as of January 1, 2001. The Commission ordered that the ISO make a compliance filing of the amended TCA, however, to conform to Commission Order No. 614. On March 23, 2001, the ISO made that compliance filing of the currently effective TCA, which was accepted by the Commission on May 1, 2001.

C. The Applications of the Southern Cities

Under the procedure outlined in Section 3.1 of the ISO Tariff, each of the Southern Cities filed with the ISO a notice of intent prior to June 30, 2002, and ensuing applications during the summer, that proposed turning over Operational Control of its undivided minority ownership interests in certain transmission facilities and Entitlements to the ISO, stating its intent to become a Participating TO on January 1, 2003.[4] The applications were posted on the ISO Home Page for Market Participant review, and comments were received from PG&E, Edison, and the California Department of Water Resources – State Water Project. The ISO responded to each of the comments and apprised each of the Southern Cities of the comments and the ISO's response.

The Southern Cities also filed on October 4, 2002 a Petition for Declaratory Order, Request for Expedited Procedures, and Request for Waiver of Filing Fee ("Petition").[5] The Petition states that the withdrawal provision of the TCA proposed by the Southern Cities is necessary to ensure that the Southern Cities' transfer of Operational Control of their Entitlements in transmission facilities to the ISO would not jeopardize the federal tax-exempt status of the bonds that financed the acquisition of their Entitlements under guidelines issued by the Internal Revenue Service. The Petition was filed to address Southern Cities' concerns that the current Participating TOs had not embraced a proposed TCA amendment required to address the withdrawal of the Southern Cities in the event of an adverse tax action. On October 29, 2002, a number of the parties submitted a motion in Docket No. EL03-7-000 requesting that the Commission extend the date for filing protests or substantive comments regarding the Southern Cities' Petition in order to allow the parties to complete their negotiations regarding the TCA. By order dated October 31, 2002, the Commission granted the October 29 motion and extended until November 14, 2002 the date for filing protests or substantive comments regarding the Petition. On November 13, 2002, the parties

4 *See* ISO Tariff, Section 3.1.1, which provides that New Participating TOs may obtain that status effective only January 1 or July 1.

5 The Petition was assigned Docket No. EL03-7-000.

submitted a second motion in Docket No. EL03-7-000 requesting that the Commission further extend the date for filing protests or substantive comments regarding the Southern Cities' Petition. By order dated November 18, 2002, the Commission granted the November 13 motion and extended until December 6, 2002 the date for filing protests or substantive comments regarding the Petition. The parties have now completed their negotiations regarding the TCA. With this filing of the enclosed executed amended TCA, the ISO understands that the Southern Cities will withdraw the Petition and that the proceedings in Docket No. EL03-7-000 will be terminated.

On October 18, 2002, Anaheim and Azusa each filed a Petition for Declaratory Order with the Commission to determine that its proffered High Voltage Transmission Revenue Requirement ("TRR") and Transmission Revenue Balancing Account ("TRBA") were appropriate for inclusion in the ISO's transmission Access Charges, together with a proposed Transmission Owner Tariff ("TO Tariff"). Parallel petitions and TO Tariffs were filed on October 29, 2002 by Riverside and Banning.

At its meeting on November 21, 2002, the ISO Governing Board unanimously approved the Southern Cities' applications to join the ISO and authorized ISO Management to file the necessary amendments to the TCA and amend the ISO Tariff to implement the TCA amendments. The Original Participating TOs, Vernon, and the Southern Cities have executed the enclosed TCA as approved by the ISO Governing Board. The ISO is filing those ISO Tariff amendments by a separate filing concurrent with this filing of the amended TCA.

In addition to this filing of the amended TCA and the companion ISO Tariff amendments, the ISO shortly will file an application pursuant to Section 203 of the FPA to assume Operational Control of the facilities and Entitlements being turned over by the Southern Cities. Moreover, in mid-December, pursuant to FPA Section 205, the ISO will be making an informational filing to revise its transmission Access Charge rates to account for the addition of the Southern Cities as Participating TOs and revise the TRBA of the current Participating TOs.

II. REVISIONS TO THE TCA

A. New Appendices Identifying the Southern Cities' Interests Being Transferred to the ISO's Operational Control

In the enclosed filing of the TCA, appendices have been added identifying the transmission interests that the Southern Cities propose to transfer to ISO Operational Control.[6] A new Appendix A has been added to describe the transmission Entitlements that each of the Southern Cities will turn over to ISO Operational Control as of

[6] These interests are consistent with the Section 203 application being filed with the Commission shortly.

January 1, 2003, and a new Appendix B has been added for each of the Southern Cities other than Banning to describe the Encumbrances associated with those Entitlements. Banning has represented that its Entitlements are not subject to any Encumbrances. The ISO, the current Participating TOs and each of the Southern Cities have agreed to these new Appendices as part of the TCA amendments filed herewith.

B. Revisions to the TCA to Address the Southern Cities' Tax-Exempt Financing Concerns

The Petition filed by the Southern Cities with the Commission, described above, states that the new withdrawal provision, proposed by the Southern Cities to be added as new Section 3.4 of the TCA and associated new definitions in TCA Appendix D, is necessary to ensure that the Southern Cities' transfer of Operational Control of their Entitlements in transmission facilities to the ISO would not jeopardize the federal tax-exempt status of the bonds that financed the acquisition of their Entitlements under guidelines issued by the Internal Revenue Service. The TCA already included in Section I of SDG&E Appendix B provides for the ability for SDG&E to withdraw the use of its transmission facilities that had been financed with tax-exempt Local Furnishing Bonds or "two county bonds". The process for withdrawal and the requirements to provide information due to an adverse tax action, however, had not been included in the body of the TCA.

The Southern Cities' proposal, which has been agreed to by the other Participating TOs as part of the TCA amendments filed herewith, specifically sets forth the ability of a Tax Exempt Participating TO to withdraw transmission facilities from ISO Operational Control due to an adverse tax action, the steps that must be taken to withdraw such facilities from the ISO Controlled Grid, and the financial implications of such withdrawal. Additionally, new Section 3.4 provides that a specific procedure will be developed jointly by all of the Participating TOs, including the Southern Cities, regarding relinquishment of Operational Control over the affected transmission facilities. As discussed above, with agreement by the Southern Cities and the current Participating TOs to this amendment, the ISO understands that the Southern Cities will be withdrawing the Petition.

C. Clarification to TCA Section 4.4.2 that the ISO Not Unreasonably Withhold Consent to Sale, Assignment, Release, or Transfer of an Entitlement

Another concern expressed by the Southern Cities regarding the TCA was that Section 4.4.2 of the TCA did not include an express provision that the ISO would not unreasonably withhold consent to a sale, assignment, release, or transfer of an Entitlement. The Southern Cities indicated that the absence of such an express provision could adversely affect their ability to maintain the tax-exempt status of the financing of their transmission interests. As the proposed amendment to Section 4.4.2 is consistent with other provisions of the TCA and is consistent with the ISO's intent, the ISO and the other Participating TOs have agreed to the clarification as part of the TCA amendments filed herewith.

D. Revision to TCA Section 4.2 to Add a Procedure for Updating the ISO Register and Restrict Its Availability

In conjunction with the revisions to the TCA to provide for the addition of the Southern Cities as Participating TOs and address the concerns raised by the Southern Cities, the ISO desired to make some revisions to the TCA to address other issues that had arisen over the course of implementing the TCA. One of those sets of revisions was to incorporate a more detailed procedure for updating the ISO Register upon changes in the transmission interests under the ISO's Operational Control and to specify that the ISO Register is no longer to be made publicly available.

The revisions to TCA Section 4.2.3 describe the procedure that will be used by the ISO to ensure that information entered into the ISO Register is accurate and consistent with the TCA. The revisions also provide a process for resolving issues over changes to the ISO Register, including a provision to ensure that the process for changing the ISO Register does not conflict with the revisions to TCA Section 4.4.2 described above or with any other provision prohibiting the ISO from withholding its consent to a transfer of a transmission interest unreasonably.

The revisions to TCA Section 4.2.4 provide that, going forward, only the Participating TOs will have access to the information in the ISO Register. This revision is based on public safety concerns that have been heightened by recent terrorist activities. The ISO is concerned that public disclosure of the contents of the ISO Register could result in impairment of system operations, unnecessarily reveal sensitive information, and pose significant security problems as to the facilities referenced therein.

The Original Participating TOs, Vernon, and the Southern Cities all have agreed to these modifications as part of the TCA amendments filed herewith.

E. Conforming of TCA Interconnection Provisions to ISO Tariff Amendment No. 39 and Clarification of Participating TO Interconnection Obligations

Another ISO-proposed revision to the TCA to address issues that had arisen over the course of implementing the TCA was to conform the provisions of Section 10 of the TCA regarding Interconnection to the provisions of ISO Tariff Amendment No. 39 regarding Interconnection, which was recently accepted by the Commission. In conjunction with that proposal, Vernon and other Participating TOs proposed to clarify the obligations of a Participating TO with regard to a request for Interconnection to a transmission facility for which the Participating TO does not have legal authority to compel Interconnection.

In the enclosed amended TCA, text has been deleted from former Sections 10.3.3, 10.3.4, and 10.4, and revisions have been made to Section 10.2.3 and renumbered Sections 10.3.3, 10.3.5, and 10.3.7 to modify those provisions to be consistent with the provisions of ISO Tariff Amendment No. 39, which was accepted by the Commission on June 4, 2002 in Docket No. EL00-95, *et al.*,[7] with a subsequent order by the Commission on August 30, 2002 specifying an effective date of June 4, 2002.[8] The primary focus of those revisions to TCA Section 10 is to provide that the provisions of the ISO Tariff regarding Interconnection will control in the event of any inconsistency with the provisions of a Participating TO's TO Tariff. The ISO was able to obtain the agreement of the Original Participating TOs, Vernon, and the Southern Cities to the foregoing amendments to the TCA as part of the TCA amendments filed herewith.

In conjunction with the revisions to provide consistency of TCA Section 10 with ISO Tariff Amendment No. 39, Vernon and other Participating TOs expressed a desire to clarify the obligations of a Participating TO that may be only the holder of a minority interest in a transmission facility, or otherwise lacking legal authority regarding the operation of that transmission facility, with regard to providing for Interconnection to that transmission facility. New Section 10.3.1 has been added to the TCA in the enclosed amendments to specify:

> Where a Participating TO does not have the legal authority to compel interconnection, the Participating TO's obligations with respect to interconnections shall be as set forth in its Commission approved TO Tariff which shall contain an obligation for the Participating TO, at a minimum, to submit or assist in the submission of, expansion and/or interconnection requests from third parties to the appropriate bodies of a project pursuant to the individual project agreements to the full extent allowed by such agreements and the applicable laws and regulations.

The ISO, the Original Participating TOs, and the Southern Cities have all agreed with Vernon as part of the TCA amendments filed herewith that the foregoing provision reflects the appropriate obligations of a Participating TO in the described circumstances.

F. <u>Deletion of ISO Grid Operations Committee and Capitalization of Defined Terms</u>

Further revisions proposed by the ISO to the TCA were to delete obsolete references to the ISO Grid Operations Committee, which has been deleted from the ISO's Bylaws and does not currently exist, and to capitalize the defined terms "Operational Control" and "Entitlement" where that capitalization had been overlooked previously. In the enclosed amended TCA, revisions have been made to Sections 4.1.1, 4.2.3, 4.5.3, 5.1.4, 5.1.5, 14.1, 14.3.3, 14.4, 17.2.2, 17.5, and 19 to implement those changes. The Original Participating TOs, Vernon, and the Southern Cities have agreed to those revisions as part of the TCA amendments filed herewith.

---

7 *San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California ISO and the California Power Exchange, et. al.*, 99 FERC ¶ 61,275 (2002).

8 *San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California ISO and the California Power Exchange, et. al.*, 100 FERC ¶ 61,235 (2002).

G. Revision to PG&E-ISO Procedure for Compliance with Transmission Reliability Standards, Updating PG&E's Encumbrances, and Adding an Omitted Provision

In conjunction with the other amendments to the TCA described herein, PG&E proposed to revise its Appendix A and Appendix B to the TCA. PG&E's proposed amendment to the Supplement to PG&E's Appendix A incorporates a revised procedure that has been implemented between PG&E and the ISO for addressing compliance with transmission reliability standards. PG&E's revisions to Appendix B of the TCA incorporate changes in PG&E's listing of its Encumbrances to reflect changes to its Encumbrances since the prior amendment to the TCA as well as to reflect PG&E's determination that certain contracts previously listed out of an abundance of caution do not contain any restrictions on the ISO's ability to exercise Operational Control over PG&E's transmission interests. In addition, it was discovered that a portion of Exhibit B-1 to PG&E Appendix B of the TCA describing PG&E's operating instructions to the ISO regarding Path 15 had been omitted from the previous Order No. 614 compliance filing of the TCA by the ISO, and that provision has been added into the attached. The ISO and PG&E have agreed to those revisions as part of the TCA amendments filed herewith, and no other signatory to the amended TCA has expressed any objection to the revisions.

H. Revisions to Edison's Entitlements and Encumbrances

In conjunction with the other amendments to the TCA described herein, Edison proposed to revise its Appendix A and Appendix B to the TCA to reflect changes in Edison's Entitlements and Encumbrances since the prior amendment to the TCA. The ISO and Edison have agreed to those revisions as part of the TCA amendments filed herewith, and no other signatory to the amended TCA has expressed any objection to the revisions.

I. Revisions to Vernon's Entitlements and Encumbrances

In conjunction with the other amendments to the TCA described herein, Vernon proposed to revise its Appendix A and Appendix B to the TCA to reflect changes in Vernon's Entitlements and Encumbrances since the prior amendment to the TCA. The ISO and Vernon have agreed to those revisions as part of the TCA amendments filed herewith, and no other signatory to the amended TCA has expressed any objection to the revisions.

J. Revisions to Requirements for Off-Site Power Supply for Nuclear Generating Facilities

In conjunction with the other amendments to the TCA described herein, PG&E and Edison proposed revisions to TCA Appendix E to reflect changes in the requirements for off-site power supply for PG&E's and Edison's nuclear generating facilities. The ISO, PG&E and Edison have agreed to those revisions as part of the

TCA amendments filed herewith, and no other signatory to the amended TCA has expressed any objection to the revisions.

K. <u>Additions and Revisions to Contact Persons</u>

To identify the persons to contact at each party for notice purposes, the TCA has been amended by revising and expanding Appendix F of the TCA. The Original Participating TOs, Vernon, and the Southern Cities have agreed to those revisions as part of the TCA amendments filed herewith.

III. EFFECTIVE DATE

The ISO respectfully requests waiver of the notice requirements of Section 35.3 of the Commission's regulations, 18 C.F.R. § 35.3, to permit the proposed changes related to Appendices A, B, D, E, and F and Sections 3.4, 4.1.1, 4.2.3, 4.2.4, 4.4.2, 4.5.3, 5.1.4, 5.1.5, 10.2.3, 10.3.1, 10.3.3, 10.3.4, 10.3.5, 10.3.7, 10.4, 14.1, 14.3.3, 14.4, 17.2.2, 17.5, and 19 of the TCA to become effective as of January 1, 2003. Granting the waiver will permit the Southern Cities to participate in the ISO's open access transmission markets and recover their Transmission Revenue Requirements through the ISO's transmission Access Charge as quickly as possible, enhancing the efficiency of the market, expanding the ISO Controlled Grid, and enabling the revision and incorporation of their transmission facilities and Entitlements into the ISO's systems as conveniently as possible. This will minimize the administrative costs to the ISO and the resulting charges to ISO Market Participants. Granting the requested waiver, therefore, is appropriate.

IV. EXPENSES

No expense or cost associated with this filing has been alleged or judged in any judicial or administrative proceeding to be illegal, duplicable, unnecessary, or demonstratively the product of discriminatory employment practices.

V. COMMUNICATIONS

The ISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

John Anders*
Deborah A. Le Vine*
The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7287
Fax: (916) 608-7296

David B. Rubin*
Julia Moore
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W.
Suite 300
Washington, D.C. 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

* Individuals designated for service pursuant to Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3).

VI. SERVICE

Copies of this transmittal letter and all attachments have been served upon the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties, including the Southern Cities, with effective Scheduling Coordinator Agreements under the ISO Tariff.

VII. SUPPORTING DOCUMENTS

Attachment A — Revised California ISO Transmission Control Agreement;[9]

Attachment B — Black-lined text showing the changes to the Transmission Control Agreement;

Attachment C — Certificates of Concurrence from Edison, PG&E, and SDG&E pursuant to Section 35.1(a) of Commission regulations, 18 C.F.R. § 35.1(a); and

Attachment D — A Notice of Filing suitable for publication in the Federal Register (also provided in electronic format).

Respectfully submitted,

Charles F. Robinson
General Counsel
John Anders
Corporate Counsel
The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

Kenneth G. Jaffe
David B. Rubin
Julia Moore
Swidler Berlin Shereff Friedman, LLP
3000 K Street, N.W.
Suite 300
Washington, DC 20007

Attorneys for the California Independent System Operator Corporation

---

9 Not included are the system maps that were filed with the TCA in Docket Nos. EC96-19 and ER96-1663 in March 1997.

ATTACHMENT A

TRANSMISSION CONTROL AGREEMENT

Among
The Independent System Operator
and
Transmission Owners

TABLE OF CONTENTS

Section **Page**

TRANSMISSION CONTROL AGREEMENT
Among
The Independent System Operator
and
Transmission Owners

The Parties to this Transmission Control Agreement ("Agreement") first dated as of ______________________________, ________, are

(1) The California Independent System Operator Corporation, a California nonprofit public benefit Corporation (the "Independent System Operator" or "ISO" which expression includes its permitted successors); and

(2) Entities owning or holding Entitlements to transmission lines and associated facilities who subscribe to this Agreement ("Transmission Owners" or "TOs", which expression includes their permitted successors and assigns).

This Agreement is made with reference to the following facts:

(i) The Legislature of the State of California enacted Assembly Bill 1890 ("AB 1890") that addressed the restructuring of the California electric industry in order to increase competition in the provision of electricity.

(ii) AB 1890 provides the means for transforming the regulatory framework of California's electric industry in ways to meet the objectives of the law.

(iii) In order to create a new market structure, AB 1890 establishes an Independent System Operator ("ISO") with centralized control of a state-wide transmission grid charged with ensuring the efficient use and reliable operation of the transmission system.

(iv) AB 1890 states that it is the intention of the California Legislature that California transmission owners commit control of their transmission facilities to the ISO with the assurances provided in the law that the financial interests of such TOs will be protected.

(v) Each TO: (1) owns, operates, and maintains transmission lines and associated facilities; and/or (2) has Entitlements to use certain transmission lines and associated facilities, with responsibilities attached thereto.

(vi) Each TO, upon satisfying the criteria for becoming a Participating TO under Section 2.2 of this Agreement, will transfer to the ISO Operational Control of certain transmission lines and associated facilities which are to be incorporated by the ISO into the ISO Controlled Grid for the purpose of allowing them to be controlled as part of an integrated Control Area.

(vii) Each Participating TO will continue to own and maintain its transmission lines and associated facilities, if any, and will retain its Entitlements, if any, and associated responsibilities.

(viii) The ISO intends to provide to each Participating TO access to the ISO Controlled Grid while exercising its Operational Control for the benefit of all Market Participants by providing non-discriminatory transmission access, Congestion Management, grid security, and Control Area services.

(ix) Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("Edison") (each a Participating TO) are entering into this agreement transferring Operational Control of their transmission facilities in reliance upon California Public Utilities Code Sections

367, 368, 375, 376 and 379 enacted as part of AB 1890 which contain assurances and schedules with respect to recovery of transition costs.

(x) The Parties desire to enter into this Agreement in order to establish the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities.

In consideration of the above and the covenants and mutual agreements set forth herein, and intending to be legally bound, the Parties agree as follows:

1. DEFINITIONS

Capitalized terms in this Agreement have the meaning set out in the Master Definitions Supplement set out in Appendix D. No subsequent amendment to the Master Definitions Supplement shall affect the interpretation of this Agreement unless made pursuant to Section 26.11.

2. PARTICIPATION IN THIS AGREEMENT

2.1. Transmission Owners:

2.1.1 Initial Transmission Owners.

The following entities are subscribing to this Agreement as of the date hereof for the purpose of applying to become Participating TOs in accordance with Section 2.2:

i. Pacific Gas and Electric Company;

ii. San Diego Gas & Electric Company; and

iii. Southern California Edison Company.

2.1.2 **Right to Become a Party.**

After this Agreement takes effect, any other owner of or holder of Entitlements to transmission lines and facilities connected to the ISO Controlled Grid may apply to the ISO under Section 2.2 to become a Participating TO and become a Party to this Agreement.

2.2. Applications for Participating TO Status; Eligibility Criteria.

2.2.1 **Application Procedures.** All applications under this Section 2.2 shall be made in accordance with the procedures adopted by the ISO from time to time and shall be accompanied by:

(i) a description of the transmission lines and associated facilities that the applicant intends to place under the ISO's Operational Control;

(ii) in relation to any such transmission lines and associated facilities that the applicant does not own, a copy of each document setting out the applicant's Entitlements to such lines and facilities;

(iii) a statement of any Encumbrances to which any of the transmission lines and associated facilities to be placed under the ISO's Operational Control are subject, together with any documents creating such Encumbrances and any dispatch protocols to give effect to them, as the ISO may require;

(iv) a statement that the applicant intends to place under the ISO's Operational Control all of the transmission lines and associated facilities referred to in Section 4.1 that it owns or, subject to the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff, to which it has Entitlements and its reasons for believing that certain lines and facilities do not form part of the applicant's transmission network pursuant to Sections 4.1.1.i and 4.1.1.ii;

(v) a statement of any Local Reliability Criteria to be included as part of the Applicable Reliability Criteria;

(vi) a description of the applicant's current maintenance practices;

(vii) a list of any temporary waivers that the applicant wishes the ISO to grant under Section 5.1.6 and the period for which it requires them;

(viii) a copy of the applicant's proposed TO Tariff, if any, must be filed;

(ix) address and contact names to which notices under this Agreement may be sent pursuant to Section 26.1;

(x) any other information that the ISO may reasonably require in order to evaluate the applicant's ability to comply with its obligations as a Participating TO; and

(xi) details of the applicant's Settlement Account.

2.2.2 **Notice of Application.** The ISO shall require the applicant to deliver to each existing Participating TO a copy of each application under this Section 2.2 and each amendment, together with all supporting documentation and to provide the public with reasonable details of its application and each amendment through WEnet or the ISO internet website. The ISO shall not grant an application for Participating TO status until it has given each other Party and the public sixty (60) days to comment on the original application and thirty (30) days to comment on each amendment.

2.2.3 **Determination of Eligibility.** Subject to Section 2.2.4, the ISO shall permit a Party who has submitted an application under this Section 2.2 to become a Participating TO if, after considering all comments received from other Parties and third parties, the ISO determines that:

i. the applicant's transmission lines and associated facilities that are to be placed under the ISO's Operational Control can be incorporated into the ISO Controlled Grid without any material adverse impact on its reliability;

ii. incorporating such transmission lines and associated facilities into the ISO Controlled Grid will not put the ISO in breach of Applicable Reliability Criteria and its obligations as a member of WSCC;

iii. objections by the ISO under Section 4.1.3 shall have been withdrawn or determined by the ISO Governing Board to be invalid;

iv. all applicable regulatory approvals of the applicant's TO Tariff have been obtained; and

v. the applicant is capable of performing its obligations under this Agreement.

Objections under Section 4.1.3 relating solely to a portion of a TO's Facilities shall not prevent the TO from becoming a Participating TO while the objections are being resolved.

2.2.4 **Challenges to Eligibility.** The ISO shall permit a Party to become a Participating TO pending the outcome of ISO ADR Procedures challenging whether or not the applicant satisfies the criteria set out in Section 2.2.3 if the ISO determines that the applicant satisfies those criteria unless otherwise ordered by FERC.

2.2.5 **Becoming a Participating TO.** A Party whose application under this Section 2.2 has been accepted shall become a Participating TO with effect from the date when its TO Tariff takes effect, either as a result of acceptance by FERC or by action of a Local Regulatory Authority, whichever is appropriate. The TO Tariff of each Participating TO shall be posted on WEnet or the ISO internet website.

2.2.6 **Procedures and Charges.** The ISO shall adopt fair and non-discriminatory procedures for processing applications under this Section 2.2. The ISO shall publish its procedures for processing applications under this Section 2.2 on WEnet or on the ISO internet website and shall furnish a copy of such procedures to FERC. Applicants shall pay all costs incurred by the ISO in processing their applications. The ISO will furnish applicants, upon request, an itemized bill for the costs of processing their application.

2.3. Tax Exempt Debt.

2.3.1 **Municipal Tax-Exempt TOs.** In the event a Municipal Tax-Exempt TO executes this Agreement in reliance upon this Section 2.3, it shall provide written notice thereof to the ISO. Notwithstanding any other provision to the contrary herein, except for this Section 2.3, no other provisions of this Agreement shall become effective with respect to a Municipal Tax-Exempt TO until such Municipal Tax-Exempt TO's nationally recognized bond counsel renders an opinion, generally of the type regarded as unqualified in the bond market, that participation in the ISO Controlled Grid in accordance with this Agreement will not adversely affect the tax-exempt status of any Municipal Tax-Exempt Debt issued by, or for the benefit of, the Municipal Tax-Exempt TO. A Municipal Tax-Exempt TO shall promptly seek, in good faith, to obtain such unqualified opinion from its bond counsel at the earliest opportunity. Upon receipt of such unqualified opinion, a Municipal Tax-Exempt TO shall provide a copy of the opinion to the ISO and all other provisions of this Agreement shall become effective with respect to such Municipal Tax-Exempt TO as of the date thereof. If the Municipal Tax-Exempt TO is unable to provide to the ISO such unqualified opinion within one year of the execution of this Agreement by the Municipal Tax-Exempt TO, without further act, deed or notice this Agreement shall be deemed to be void *ab initio* with respect to such Municipal Tax-Exempt TO.

2.3.2 **Acceptable Encumbrances.** A Transmission Owner that has issued Local Furnishing Bonds may become a Participating TO under Section 2.2 even though covenants or restrictions applicable to the Transmission Owner's Local Furnishing Bonds require the ISO's Operational Control to be exercised subject to Encumbrances, provided that such Encumbrances do not materially impair the ISO's ability to meet its obligations under the ISO Tariff or the Transmission Owner's ability to comply with the TO Tariff.

2.3.3 **Savings Clause.** Nothing in this Agreement shall compel any Participating TO or Municipal Tax-Exempt TO which has issued Tax-Exempt Debt to violate restrictions applicable to transmission facilities financed with Tax-Exempt Debt or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995.

3. EFFECTIVE DATE, TERM AND WITHDRAWAL

3.1. Effective Date.

This Agreement shall become effective as of the latest of:

i. the date that it is signed by the ISO and the Transmission Owners referred to in Section 2.1.1;

ii. the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decision 97-12-131; and

iii. the date when this Agreement is accepted for filing and made effective by the FERC.

3.2. Term.

This Agreement shall remain in full force and effect until terminated: (1) by operation of law or (2) the withdrawal of all Participating TOs pursuant to Section 3.3 or Section 4.4.1.

3.3. Withdrawal.

3.3.1 **Notice.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement on two years' prior written notice to the other Parties.

3.3.2 **Sale.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement if that Participating TO sells or otherwise disposes of all of the transmission facilities and Entitlements that the Participating TO placed under the ISO's Operational Control, subject to the requirements of Section 4.4.

3.3.3 **Conditions of Withdrawal.** Any withdrawal from this Agreement pursuant to Section 3.3.1 or Section 3.3.2 shall be contingent upon the withdrawing party obtaining any necessary regulatory approvals for such withdrawal. The withdrawing Participating TO shall make a good faith effort to ensure that its withdrawal does not unduly impair the ISO's ability to meet its Operational Control responsibilities as to the facilities remaining within the ISO Controlled Grid.

3.3.4 **Publication of Withdrawal Notices.** The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.3.

3.4 Withdrawal Due to Adverse Tax Action.

3.4.1 **Right to Withdraw Due To Adverse Tax Action.** Subject to Sections 3.4.2 through 3.4.4, in the event an Adverse Tax Action Determination identifies an Impending Adverse Tax Action or an Actual Adverse Tax Action, a Tax Exempt Participating TO may exercise its right to Withdraw for Tax Reasons. The right to Withdraw for Tax Reasons, in accordance with the provisions of this Section 3.4, shall not be subject to any approval by the ISO, the FERC or any other Party.

3.4.2 **Adverse Tax Action Determination.**

3.4.2.1 A Tax Exempt Participating TO shall provide to all other Parties written notice of an Adverse Tax Action Determination and a copy of the Tax Exempt Participating TO's (or its joint action agency's) nationally recognized bond counsel's opinion or an IRS determination supporting such Adverse Tax Action Determination. Such written notice shall be provided promptly under the circumstances, but in no event more than 15 working days from the date of receipt of such documents.

3.4.2.2 The Adverse Tax Action Determination shall include (i) the actual or projected date of the Actual Adverse Tax Action and (ii) a description of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the Tax Exempt Debt that is the subject of such Adverse Tax Action Determination. A Tax Exempt Participating TO shall promptly notify all other Parties in writing in the event the actual or projected date of the Actual Adverse Tax Action changes. The Tax Exempt Participating TO's determination of the actual or projected date of the Actual Adverse Tax Action shall be binding upon all Parties.

3.4.2.3 Any transmission lines, associated facilities or Entitlements of the Tax Exempt Participating TO not identified in both the Adverse Tax Action Determination and the written notice of Withdrawal for Tax Reasons shall remain under the ISO's Operational Control.

3.4.3 **Withdrawal Due to Impending Adverse Tax Action.** A Tax Exempt Participating TO may Withdraw for Tax Reasons prior to an Actual Adverse Tax Action if such Tax Exempt Participating TO provides prior written notice of its Withdrawal for Tax Reasons to all other Parties as required in Sections 3.4.3(i) through 3.4.3(iv).

i. In the event the date of the Adverse Tax Action Determination is seven months or more from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least six months in advance of the projected date of the Actual Adverse Tax Action.

ii. In the event the date of the Adverse Tax Action Determination is less than seven months but more than two months from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to

Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least 30 days in advance of the projected date of the Actual Adverse Tax Action.

iii. In the event the date of the Adverse Tax Action Determination is between two months and one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least 15 days in advance of the projected date of the Actual Adverse Tax Action.

iv. In the event the date of the Adverse Tax Action Determination is less than one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO shall have up to 15 days following the date of the Adverse Tax Action Determination to exercise its right to Withdraw for Tax Reasons, and if so exercised shall provide no later than one day thereafter written notice of its Withdrawal for Tax Reasons to all other Parties.

v. With respect to Sections 3.4.3(i) through 3.4.3(iii), upon receipt by the ISO of a notice to Withdraw for Tax Reasons, the ISO shall promptly begin working with the applicable Tax Exempt Participating TO to relinquish the ISO's Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, provided that such Operational Control must be relinquished by the ISO no later than five days prior to the projected date of the Actual Adverse Tax Action. With respect to Section 3.4.3(iv), (1) if the notice of Withdrawal for Tax Reasons is received by the ISO at least six days prior to the projected date of the

Actual Adverse Tax Action, Operational Control over the affected transmission lines, associated facilities or Entitlements must be relinquished by the ISO to such Tax Exempt Participating TO no later than five days prior to the projected date of the Actual Adverse Tax Action, or (2) if the notice of Withdrawal for Tax Reasons is received by the ISO any time after six days prior to the projected date of the Actual Adverse Tax Action, the ISO shall on the next day relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.4 **Withdrawal Due to Actual Adverse Tax Action.** In addition to the foregoing, upon the occurrence of an Actual Adverse Tax Action, the affected Tax Exempt Participating TO may immediately Withdraw for Tax Reasons. The Tax Exempt Participating TO shall have up to 15 days from the date of the Adverse Tax Action Determination with respect to an Actual Adverse Tax Action to exercise its right to Withdraw for Tax Reasons. If the Tax Exempt Participating TO determines to exercise its right to Withdraw for Tax Reasons, upon receipt of the notice of Withdrawal for Tax Reasons, the ISO shall immediately relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.5 **Alternate Date To Relinquish Operational Control.** Notwithstanding anything to the contrary in this Section 3.4, the ISO and a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons may mutually agree in writing to an alternate date that the ISO shall relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such

Tax Exempt Participating TO. If the ISO or a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons desires an alternate date from the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, such party promptly shall give written notice to the other, and each agrees to negotiate in good faith, for a reasonable period of time, to determine whether or not they can reach mutual agreement for such an alternate date; provided, however, such good faith negotiations are not required to be conducted during the five days preceding the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements.

3.4.6 **Procedures to Relinquish Operational Control.** The ISO shall implement a procedure jointly developed by all Parties to relinquish Operational Control over the affected transmission lines, associated facilities, or Entitlements as provided in this Section 3.4.

3.4.7 **Right to Rescind Notice of Withdrawal for Tax Reasons.** At any time up to two days prior to the ISO's relinquishment to the Tax Exempt Participating TO of Operational Control over the affected transmission lines, associated facilities or Entitlements, a Tax Exempt Participating TO may rescind its notice of Withdrawal for Tax Reasons by providing written notice thereof to all other Parties, and such notice shall be effective upon receipt by the ISO.

3.4.8 **Amendment of Agreement.** Following the relinquishment by the ISO of Operational Control in accordance with this Section 3.4, the ISO promptly shall prepare the necessary changes to this Agreement, submit the changes to the Participating TOs for execution and take whatever regulatory action, if any, that is required to properly reflect the Withdrawal for Tax Reasons.

3.4.9 **Provision of Information by ISO.** To assist Tax Exempt Participating TOs in identifying at the earliest opportunity Impending Adverse Tax Actions or Actual Adverse Tax Actions, the ISO promptly shall provide to Participating TOs any non-confidential information regarding any ISO plans, actions or operating protocols that the ISO believes might adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO.

3.4.10 **Publication of Notices.** The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.4.

4. TRANSFER OF OPERATIONAL CONTROL

4.1. TO Facilities and Rights Provided to the ISO.

4.1.1 **ISO Controlled Grid.** Subject to Section 4.1.2 and the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff and subject to the applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements, each Participating TO shall place under the ISO's Operational Control the transmission lines and associated facilities forming part of the transmission network that it owns or to which it has Entitlements. The Initial Transmission Owners identified in Section 2.1.1 shall be deemed to have placed such transmission lines and associated facilities under the ISO's Operational Control as of the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decisions 97-

12-131 and 98-01-053. Any transmission lines or associated facilities that the ISO determines not to be necessary to fulfill the ISO's responsibilities under the ISO Tariff in accordance with Section 4.1.3 of this Agreement shall not be treated as part of a Participating TO's network for the purposes of this Section 4.1. The ISO shall recognize the rights and obligations of owners of jointly-owned facilities which are placed under the ISO's Operational Control by one or more but not all of the joint owners. The ISO shall, in exercise of Operational Control transferred to it, ensure that the operating obligations, as specified by the Participating TO pursuant to Section 6.4.2 of this Agreement, for the contracts referenced in Appendix B are performed. Any other terms of such contracts shall not be the responsibility of the ISO. The following transmission lines and associated facilities are also deemed not to form part of a Participating TO's transmission network:

i. directly assignable radial lines and associated facilities interconnecting generation (other than those facilities which may be identified from time to time interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support) and

ii. lines and associated facilities classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test and other facilities excluded consistent with FERC established criteria for determining facilities subject to ISO Operational Control.

4.1.2 **Transfer of Facilities by Local Furnishing Participating TOs.** This Section 4.1.2 is applicable only to the enlargement of transmission capacity by Local Furnishing Participating TOs. The ISO shall not require a Local Furnishing

Participating TO to enlarge its transmission capacity except pursuant to an order under Section 211 of the FPA directing the Local Furnishing Participating TO to enlarge its transmission capacity as necessary to provide transmission service as determined pursuant to Section 3.2.9 of the ISO Tariff. If an application under Section 211 of the FPA is filed by an eligible entity (or the ISO acting as its agent), the Local Furnishing Participating TO shall thereafter, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 212(c) of the FPA. Upon receipt of a final order from FERC under Section 211 of the FPA that is no longer subject to rehearing or appeal, such Local Furnishing Participating TO shall enlarge its transmission capacity to comply with that FERC order and shall transfer to the ISO Operational Control over its expanded transmission facilities in accordance with this Section 4.

4.1.3 **Refusal of Facilities.** The ISO may refuse to exercise Operational Control over certain of an applicant's transmission lines, associated facilities or Entitlements if it determines during the processing of an application under Section 2.2 that any one or more of the following conditions exist:

i. The transmission lines, associated facilities or Entitlements do not meet or do not permit the ISO to meet the Applicable Reliability Criteria and the applicant fails to give the ISO a written undertaking to take all good faith actions necessary to ensure that those transmission lines, facilities or Entitlements, as the case may be, meet the Applicable Reliability Criteria within a reasonable period from the date of the applicant's application under Section 2.2 as determined by the ISO.

ii. The transmission lines, associated facilities or Entitlements are subject to Encumbrances that unduly impair the ISO's ability to exercise its Operational Control over them in accordance with the ISO Tariff and the applicant fails to give the ISO a written undertaking to negotiate in good faith to the extent permitted by the applicable contract the removal of the Encumbrances identified by the ISO which preclude it from using unused capacity on the relevant transmission lines. If the applicant provides such written undertaking but is unable to negotiate the removal of such Encumbrances to the extent required by the ISO, the ADR Procedure shall be used to resolve any disputes between the ISO and the applicant. For this purpose, Non-Participating TOs may utilize ISO ADR procedures on a voluntary basis.

iii. The transmission lines, associated facilities and Entitlements are located in a Control Area outside of California, are operated under the direction of another Control Area or independent system operator, and cannot be integrated into the ISO Controlled Grid due to technical considerations.

If the ISO refuses to accept any of an applicant's transmission lines, facilities or Entitlements, then that applicant shall have the right to notify the ISO within a reasonable period from being notified of such refusal that it will not proceed with its application under Section 2.2.

4.1.4 **Facilities Initially Placed Under the ISO's Operational Control.** The transmission lines, associated facilities and Entitlements which each Participating TO places under the ISO's Operational Control on the date that this Agreement takes effect with respect to it shall be identified in Appendix A.

4.1.5 **Warranties.** Each Participating TO warrants that as of the date on which it becomes a Participating TO pursuant to Section 2.2.5:

i. the transmission lines and associated facilities that it is placing under the ISO's Operational Control and the Entitlements that it is making available for the ISO's use are correctly identified in Appendix A (as amended in accordance with this Agreement); that the Participating TO has all of the necessary rights and authority to place such transmission lines and associated facilities under the ISO's Operational Control subject to the terms and conditions of all agreements governing the use of such transmission lines and associated facilities; and that the Participating TO has the necessary rights and authority to transfer the use of such Entitlements to the ISO subject to the terms and conditions of all agreements governing the use of such Entitlements;

ii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control are not subject to any Encumbrances except as disclosed in Appendix B (as amended in accordance with this Agreement);

iii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control meet the Applicable Reliability Criteria (ARC) for the relevant Participating TO except as disclosed in writing to the ISO. As to the Local Reliability Criteria component of ARC, each Participating TO has provided the ISO with such information required to identify such Participating TO's Local Reliability Criteria.

4.2. The ISO Register.

4.2.1 **Register of Facilities Subject to ISO Operational Control.** The ISO shall maintain a register (the "ISO Register") of all transmission lines, associated facilities and Entitlements that are for the time being subject to the ISO's Operational

Control. The ISO Register shall also indicate those facilities over which the ISO has asserted temporary control pursuant to Section 4.5.2 and whether or not the ISO has commenced proceedings under Section 203 of the FPA in relation to them.

4.2.2 **Contents.** The ISO Register shall disclose in relation to each transmission line and associated facility subject to the ISO's Operational Control:

i. the identity of the Participating TO responsible for its operation and maintenance and its owner(s) (if other than the Participating TO);

ii. the date on which the ISO assumed Operational Control over it and, in the case of transmission lines and associated facilities over which it has asserted temporary Operational Control, the date on which it relinquished Operational Control over it;

iii. the date of any change in the identity of the Participating TO responsible for its operation and maintenance or in the identity of its owner; and

iv. its applicable ratings.

4.2.3 **Updates.** In order to keep the ISO Register current, each Participating TO shall submit an ISO Register change for each addition or removal of a transmission line or associated facility or Entitlement from the ISO's Operational Control or any change in a transmission line or associated facility's ownership, rating or the identity of the responsible Participating TO. The ISO shall review each ISO Register change for accuracy and to assure that all requirements of this Agreement have been met. If the ISO determines that a submitted ISO Register change is accurate and meets all the requirements of this Agreement, the ISO will modify the ISO Register to incorporate such change by the end of the next Business Day. The ISO may determine that an ISO Register change cannot be implemented due to (a) lack of clarity or necessary information, or (b) conflict between the revised rating and applicable contractual, regulatory or legal requirements including operating considerations, or other conflict with the terms of this Agreement. In such event, the ISO promptly will communicate to the Participating TO the reason that the ISO cannot implement the ISO Register change and will work with the Participating TO in an attempt to resolve promptly the concerns leading to the ISO's refusal to implement an ISO Register change. The ISO consent required with respect to a sale, assignment, release, transfer or other disposition of transmission lines, associated facilities or Entitlements as provided in Section 4.4 hereof shall not be withheld by the ISO as a result of an ISO determination that an ISO Register change cannot be implemented pursuant to this Section 4.2.3.

4.2.4 **Publication.** The ISO shall make the ISO Register available to the Participating TOs on WEnet or a secure ISO-maintained internet website.

4.2.5 **Duty to Maintain Records.** The ISO shall maintain the ISO Register in a form that conveniently shows the entities responsible for operating, maintaining and controlling the transmission lines and associated facilities forming part of the ISO Controlled Grid at any time and the periods during which they were so responsible.

4.3. Rights and Responsibilities of Participating TOs.

Each Participating TO shall retain its benefits of ownership and its rights and responsibilities in relation to the transmission lines and associated facilities placed under the ISO's Operational Control except as otherwise provided in this Agreement.

Participating TOs shall be responsible for operating and maintaining those lines and facilities in accordance with this Agreement, the Applicable Reliability Criteria, the Operating Procedures and other criteria, ISO Protocols, procedures and directions of the ISO issued or given in accordance with this Agreement. Rights and responsibilities that have not been transferred to the ISO as operating obligations under Section 4.1.1 of this Agreement remain with the Participating TO. This Agreement shall have no effect on the remedies for breach or non-performance available to parties to existing interconnection, integration, exchange, operating joint ownership and joint participation agreements.

4.4. Sale or Disposal of Transmission Facilities or Entitlements.

4.4.1 **Sale or Disposition.**

4.4.1.1 No Participating TO shall sell or otherwise dispose of any lines or associated facilities forming part of the ISO Controlled Grid without the ISO's prior written consent, which consent shall not be unreasonably withheld.

4.4.1.2 As a condition to the sale or other disposition of any lines or associated facilities forming part of the ISO Controlled Grid to an entity that is not a Participating TO, the Participating TO shall require the transferee to assume in writing all of the Participating TO's obligations under this Agreement (but without necessarily requiring it to become a Participating TO for the purposes of the ISO Tariff or a TO Tariff).

4.4.1.3 Any subsequent sale or other disposition by a transferee referred to in Section 4.4.1.2 shall be subject to this Section 4.4.1.

4.4.1.4 A transferee referred to in Section 4.4.1.2 that does not become a

Participating TO shall have the same rights and responsibilities regarding withdrawal that a Participating TO has under Sections 3.3.1 and 3.3.3.

4.4.2 **Entitlements.** No Participating TO shall sell, assign, release, or transfer any Entitlements that have been placed under the ISO's Operational Control without the ISO's prior written consent, which consent shall not be unreasonably withheld, provided that such written consent is not required for such release or transfer to another Participating TO who is not in any material respect in breach of its obligations under this Agreement and who has not given notice of its intention to withdraw from this Agreement.

4.4.3 **Encumbrances.** No Participating TO 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. The ISO shall give its consent to the creation or extension of an Encumbrance within thirty (30) days after receiving a written request for its consent disclosing in reasonable detail the nature of and reasons for the proposed change unless the ISO reasonably determines that the change is inconsistent with the Participating TO's obligations under the ISO Tariff or the TO Tariff or that the change may materially impair the ISO's ability to exercise Operational Control over the relevant lines or facilities or may reduce the reliability of the ISO Controlled Grid. Exercise of rights under an Existing Contract shall not be deemed to create a new Encumbrance for the purposes of this Section 4.4.3.

4.5. Procedure for Designating ISO Controlled Grid Facilities.

4.5.1 **Additional Facilities.** If the ISO determines that it requires Operational Control over additional transmission lines and associated facilities not then constituting part of the ISO Controlled Grid in order to fulfill its responsibilities in relation to the ISO Controlled Grid then the ISO shall apply to FERC pursuant to Section 203 of the Federal Power Act, and shall make all other regulatory filings necessary to obtain approval for such change of control and shall serve a copy of all such applications on the affected Participating TO and the owner of such lines and facilities (if other than the Participating TO). In the event that a Party invokes the dispute resolution provisions identified in Section 15 with respect to the transfer of Operational Control over a facility, such facility shall not be transferred while the dispute resolution process is pending except pursuant to Section 4.5.2.

4.5.2 **Temporary Operational Control.** The ISO may exercise temporary Operational Control over any transmission lines or associated facilities of a Participating TO (including lines and facilities to which the Participating TO has sufficient Entitlement to permit the ISO to exercise Operational Control over them) that do not then form part of the ISO Controlled Grid:

i. in order to prevent or remedy an imminent System Emergency;

ii. on reasonable notice, for a period not exceeding ninety (90) days, in order to determine whether exercising Operational Control over the relevant lines and facilities will assist the ISO to meet Applicable Reliability Criteria or to fulfill its Control Area responsibilities under the ISO Tariff; or

iii. subject to any contrary order of FERC, pending the resolution of the procedures referenced in Section 4.5.1.

4.5.3 **Return of Control of Facilities.** Control of facilities over which the ISO has assumed temporary Operational Control will be returned to the appropriate Participating TO when the conditions set forth in Section 4.5.2 no longer require the ISO to assume such temporary control.

4.5.4 **Transmission Expansion Projects.** Any transmission expansion projects carried out pursuant to Section 3.2 of the ISO Tariff shall be subject to the ISO's Operational Control from the date that it goes into service or after such period as the ISO deems to be reasonably necessary for the ISO to integrate the project into the ISO Controlled Grid.

4.6. TOs Control Centers.

4.6.1 **ISO's Right to Occupy Participating TOs Control Centers.** From the ISO Operations Date until the date when, in the reasonable opinion of the ISO, the ISO Control Center is established in accordance with Section 2.3.1.1 of the ISO Tariff, each Participating TO shall allow the ISO access to and such rights to occupy the Participating TO's existing control centers as the ISO reasonably requires for the purposes of exercising Operational Control of the ISO Controlled Grid.

4.6.2 **Confidentiality.** The parties to this Agreement shall implement Section 4.6.1 in conformity with the confidentiality requirements of Section 26.3.

4.7. Termination of ISO's Operational Control.

4.7.1 **Release from ISO's Operational Control.** Subject to Section 4.7.2, the ISO may relinquish its Operational Control over any transmission lines and associated facilities constituting part of the ISO Controlled Grid if, after consulting the

Participating TOs owning or having Entitlements to them, the ISO determines that it no longer requires to exercise Operational Control over them in order to meet its Control Area responsibilities and they constitute:

i. directly assignable radial lines and associated facilities interconnecting Generation (other than lines and facilities interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support);

ii. lines and associated facilities which, by reason of changes in the configuration of the ISO Controlled Grid, should be classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test, or should otherwise be excluded from the facilities subject to ISO Operational Control consistent with FERC established criteria; or

iii. lines and associated facilities which are to be retired from service in accordance with Good Utility Practice.

4.7.2 **Procedures.** Before relinquishing Operational Control over any transmission lines or associated facilities pursuant to section 4.7.1, the ISO shall inform the public through WEnet and the ISO internet website of its intention to do so and of the basis for its determination pursuant to Section 4.7.1. The ISO shall give interested parties not less than 45 days within which to submit written objections to the proposed removal of such lines or facilities from the ISO's Operational Control. If the ISO cannot resolve any timely objections to the satisfaction of the objecting parties and the Participating TOs owning or having Entitlements to the lines and facilities, such parties, Participating TOs, or the ISO may refer any disputes for resolution pursuant to the ISO

ADR Procedures in Section 13 of the ISO Tariff. Alternatively, the ISO may apply to FERC for its approval of the ISO's proposal.

4.7.3 **Duty to Update ISO Register.** The ISO shall promptly record any change in Operational Control pursuant to this Section 4.7 in the ISO Register in accordance with Section 4.2.3.

5. INDEPENDENT SYSTEM OPERATOR

5.1. Control Area Operator.

5.1.1 **Membership of WSCC and RTGs.** 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 Regional Transmission Groups (RTGs) in that capacity. No Party shall take any position before the WSCC or an RTG that is inconsistent with a binding decision reached through the dispute resolution process referenced in Section 15, provided that the scope of the decision was no greater than the issues set forth in the statement of claims published by the ISO pursuant to Section 13.2.2 of the ISO Tariff.

5.1.2 **Operational Control.** The ISO shall exercise Operational Control over the ISO Controlled Grid for the purpose of:

i. providing a framework for the efficient transmission of electricity across the ISO Controlled Grid in accordance with the ISO Tariff;

ii. securing compliance with all Applicable Reliability Criteria;

iii. scheduling transactions for Market Participants to provide open and non-discriminatory access to the ISO Controlled Grid in accordance with the ISO

Tariff;

iv. relieving Congestion; and

v. to the extent provided in this Agreement, assisting Market Participants to comply with other operating criteria, contractual obligations and legal requirements binding on them.

5.1.3 **Duty of Care.** The ISO shall have the exclusive right and responsibility to exercise Operational Control over the ISO Controlled Grid, subject to and in accordance with Applicable Reliability Criteria and the operating criteria established by the NRC operating licenses for nuclear generating units as provided in Appendix E pursuant to Section 6.4.2. The ISO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, Existing Contracts, the ISO Tariff and the Operating Procedures. The ISO shall not direct a Participating TO to take any action which would require a Participating TO to operate its transmission facilities in excess of their applicable rating as established or modified from time to time by the Participating TO pursuant to Section 6.4 except in a System Emergency where such a direction is consistent with Applicable Reliability Criteria.

5.1.4 **Operating Procedures.** The ISO shall, in consultation with the Participating TOs and other Market Participants, promulgate Operating Procedures governing its exercise of Operational Control over the ISO Controlled Grid in accordance with this Agreement. The ISO shall provide copies of the Operating Procedures and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WEnet or the ISO internet website.

5.1.5 **Applicable Reliability Criteria**. The ISO shall, in consultation with Participating TOs and other Market Participants, develop and promulgate Applicable Reliability Criteria for the ISO Controlled Grid, which shall be in compliance with the reliability standards promulgated by NERC, WSCC, Local Reliability Criteria and NRC grid criteria related to operating licenses for nuclear generating units. The ISO shall provide copies of the Applicable Reliability Criteria and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WEnet or the ISO internet website.

5.1.6 **Waivers**. The ISO may grant to any Participating TO whose transmission facilities do not meet the Applicable Reliability Criteria when it becomes a party to this Agreement such waivers from the Applicable Reliability Criteria as the Participating TO reasonably requires to prevent it from being in breach of this Agreement while it brings its transmission facilities into full compliance. Such waivers shall be effective for such period as the ISO shall determine. A Participating TO who has been granted a waiver made under this Section 5.1.6 shall bring its transmission facilities into compliance with the Applicable Reliability Criteria before the expiration of the relevant waivers and in any event as soon as reasonably practical.

5.1.7 **Operational Protocols**. In exercising Operational Control over the ISO Controlled Grid, the ISO shall comply with the operational protocols to be provided in accordance with Section 6.4.2, as they may be amended from time to time to take account of the removal and relaxation of any Encumbrances to which the ISO Controlled Grid is subject. Participating TOs whose transmission lines and associated facilities are subject to Encumbrances shall make all reasonable efforts to remove or relax those Encumbrances in order to permit the operational protocols to be amended in such manner as the ISO may reasonably require, to the extent permitted by Existing Contracts and applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements.

5.1.8 **System Emergencies.** 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.

5.1.9 **Reporting Criteria.** The ISO shall comply with the reporting requirements of the WSCC, NERC, NRC and regulatory bodies having jurisdiction over it. Participating TOs shall provide the ISO with information that the ISO may require to meet this obligation.

5.2. Monitoring.

5.2.1 **System Requirements.** The ISO shall establish reasonable metering, monitoring, and data collection standards and requirements for the ISO Controlled Grid, consistent with WSCC and NERC standards.

5.2.2 **System Conditions.** The ISO shall monitor and observe real time system conditions throughout the ISO Controlled Grid, as well as key facilities in other areas of the WSCC region.

5.2.3 **Power Management System.** The ISO shall install a computerized Power Management System (PMS) to monitor transmission facilities in the ISO Controlled Grid. A Participating TO may at its own expense and for its own internal management purposes install a read only PMS workstation that will provide the Participating TO with the same displays the ISO uses to monitor the Participating TO's transmission facilitates.

5.2.4 **Data**. Unless otherwise mutually agreed, the ISO shall obtain real time monitoring data for the facilities listed in the ISO Register from the Participating TOs through transfers to the ISO of data available from the Energy Management Systems (EMS) of the Participating TOs.

5.3. Coordination Role.

The ISO shall perform a WSCC security coordinator function as designated by the WSCC. As such, the ISO shall have all necessary powers as described in this Agreement in relation to Participating TOs to meet the applicable NERC and WSCC requirements for security coordinators. The ISO shall assume this responsibility concurrent with the commencement of ISO Operational Control.

5.4. Public Information.

5.4.1 **WEnet**. The ISO shall develop a public information board ("WEnet" or ISO internet website) for the ISO Controlled Grid in accordance with the provisions in Section 6 of the ISO Tariff.

5.4.2 **Access to ISO Information**. The ISO shall permit the general public to inspect and copy other information in its possession, other than information to be kept confidential under Section 26.3, provided that the costs of providing documents for inspection, including any copying costs, shall be borne by the requester.

5.5. Costs

The ISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on a Participating TO without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by a Participating TO of capital and operation and maintenance costs incurred to comply with ISO-imposed reliability requirements, operating requirements, or performance standards, the ISO shall, at the request of the Participating TO, provide specific information regarding the nature of, and need for, the ISO-imposed requirements or standards to enable the Participating TO to use this information in support of cost recovery through rates and tariffs.

6. PARTICIPATING TRANSMISSION OWNERS

6.1. Physical Operation of Facilities.

6.1.1 **Operation.** Each Participating TO shall have the exclusive right and responsibility to operate and maintain its transmission facilities and associated switch gear and auxiliary equipment (including facilities that it operates under Entitlements).

6.1.2 **ISO Operating Orders.** Each Participating TO shall operate its transmission facilities in compliance with ISO Protocols, the Operating Procedures (including emergency procedures in the event of communications failure) and 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 TO 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 seek confirmation of the relevant ISO order.

6.1.3 **Duty of Care**. In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, ISO Protocols, the Operating Procedures and the Applicable Reliability Criteria.

6.1.4 **Outages**. Each Participating TO shall obtain approval from the ISO before taking out of service and returning to service any facility identified pursuant to Section 4.2.1 in the ISO Register, except in cases involving immediate hazard to the safety of personnel and the general public or imminent damage to facilities where there is not time to contact the ISO. The Participating TO shall promptly notify the ISO of such situations.

6.1.5 **Return to Service**. After a System Emergency or Forced Outage, the Participating TO shall restore to service the transmission facilities under the ISO's Operational Control as soon as possible and in the priority order determined by the ISO. The ISO's Operating Procedures shall give priority to restoring offsite power to nuclear generating units, in accordance with criteria specified by the Participating TOs under the design basis and licensing requirements of the NRC licenses applicable to such nuclear units and any other Regulatory Must-Run Generation whose operation is critical for the protection of wildlife and the environment.

6.1.6 **Written Report**. Within a reasonable time, the Participating TO shall provide the ISO with a written report, consistent with Section 17, describing the circumstances and the reasons for any Forced Outage, including outages under Section 6.1.4.

6.2. Transmission Service.

6.2.1 **Compliance with Tariffs.** Participating TOs shall allow access to their transmission facilities (including any that are not for the time being under the ISO's Operational Control) only on the terms of the ISO Tariff and the TO Tariff.

6.2.2 **Release of Scheduling Rights.** When required by the ISO, a Participating TO shall release all of its scheduling rights over the transmission lines and associated facilities that are part of the ISO Controlled Grid to the extent such rights are established through Existing Contracts among or between Participating TOs, as provided in the ISO Tariff.

6.3. Other Responsibilities.

Each Participating TO shall inspect, maintain, repair, replace and maintain the rating and technical performance of its facilities under the ISO's Operational Control in accordance with the Applicable Reliability Criteria (subject to any waivers granted pursuant to Section 5.1.6) and the performance standards established under Section 14.

6.4. Technical Information and Protocols.

6.4.1 **Information to be Provided.** Each Participating TO shall provide to the ISO prior to the effective date of this Agreement, and in a format acceptable to the ISO:

i. Technical specifications for any facilities under the ISO's Operational Control, as the ISO may require;

ii. The applicable ratings of all transmission lines and associated facilities listed in Appendix A; and

iii. A copy of each document creating an Entitlement or Encumbrance.

The Participating TO shall promptly notify the ISO in writing or mutually acceptable electronic format of any subsequent changes in such technical specifications, ratings, Entitlements or Encumbrances.

6.4.2 **Protocols for Encumbered Facilities.** A Party that is placing a transmission line or associated facility (including an Entitlement) that is subject to an Encumbrance under the Operational Control of the ISO shall develop protocols for its operation which shall: (1) reflect the rights the Party has in such facility, and (2) give effect to any Encumbrance on such facility. Such protocols shall be delivered to the ISO for review not less than ninety (90) days prior to the date on which the ISO is expected to assume Operational Control of any such facility. The ISO shall review each protocol and shall cooperate with the relevant Party to assure that operations pursuant to the protocol are feasible and that the protocol is consistent with the applicable rights and Encumbrances. To the extent such protocol is required to be filed at FERC, the relevant Transmission Owner shall file such protocol not less than sixty (60) days prior to the date on which the ISO is expected to assume Operational Control of the relevant facility. Protocols to implement the operating criteria established by the NRC operating licenses for nuclear generating units are provided in Appendix E.

6.5. EMS/SCADA System.

Each Participating TO shall operate and maintain its EMS/SCADA systems and shall allow the ISO access to the Participating TO's data from such systems relating to the facilities under the ISO's Operational Control. The ISO, at its own cost, may, if it considers it necessary for the purpose of carrying out its responsibilities under this Agreement, acquire, install and maintain additional monitoring equipment on any Participating TO's property.

6.6. Single Point Of Contact.

Each Participating TO shall provide the ISO with an appropriate single point of contact for the coordination of operations under this Agreement.

7. SYSTEM OPERATION AND MAINTENANCE

7.1. Scheduled Maintenance.

The Parties shall forecast and coordinate Maintenance Outage plans in accordance with Section 2.3.3 of the ISO Tariff.

7.2. Exercise of Contractual Rights.

In order to facilitate Maintenance Outage coordination of the ISO Controlled Grid by the ISO, each Participating TO shall, to the extent that the Participating TO has contractual rights to do so: (1) coordinate Maintenance Outages with Non-Participating Generators; and (2) exercise its contractual rights to require maintenance by Non-Participating Generators in each case in such manner as the ISO approves or requests. The requirements of this Section 7.2 shall not apply to any Non-Participating Generator with a rated capability of less than 50 MW.

7.3. Unscheduled Maintenance.

7.3.1 **Notification.** A Participating TO shall notify the ISO of any faults on the ISO Controlled Grid or any actual or anticipated Forced Outages as soon as it becomes aware of them, in accordance with Section 2.3.3 of the ISO Tariff.

7.3.2 **Returns to Service.** The Participating TO shall take all steps necessary, consistent with Good Utility Practice and in accordance with the ISO Tariff and ISO Protocols, to prevent Forced Outages and to return to operation, as soon as possible, any facility under the ISO's Operational Control that is the subject of a Forced Outage.

8. AUXILIARY EQUIPMENT AND ISO CONTROLLED GRID CRITICAL PROTECTIVE SYSTEMS

8.1. Designations of Auxiliary Equipment and Critical Protective Systems.

8.1.1 **System Security.** The ISO shall exercise Operational Control over all facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security. These will be designated as ISO Controlled Grid Critical Protective Systems. Participating TOs shall coordinate with the ISO, Generators and UDCs to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with Participating TO's, Generator's and UDC's protective systems.

8.1.2 **Remedial Action Schemes.** The ISO shall exercise Operational Control over Remedial Action Schemes that are designated as ISO Controlled Grid Critical Protective Systems. Participating TOs who are parties to contracts affecting Remedial Action Schemes shall make all reasonable efforts to amend those contracts in order to permit the relevant Remedial Action Scheme to be operated in such manner as the ISO may reasonably require.

8.1.3 **Identification**. The ISO, in conjunction with each Participating TO shall identify and designate all ISO Controlled Grid Critical Protective Systems operating in relation to its transmission facilities. The ISO may change the designation of facilities and sites as ISO Controlled Grid Critical Protective Systems from time to time.

8.2. Operation and Maintenance of Auxiliary Equipment and Critical Protective Systems.

8.2.1 **Operation and Maintenance**. The system operation and maintenance coordination functions, including ISO Maintenance Outage authorization requirements set forth in the ISO Tariff, shall apply to auxiliary equipment associated with the facilities identified in the ISO Register.

8.2.2 **Settings and Functionality**. Each Participating TO shall maintain the settings or functionality of ISO Controlled Grid Critical Protective Systems and shall not change or disable such settings or functionality without the prior written agreement of the ISO.

8.2.3 **Protective Relay Systems**. Each Participating TO shall continue to install, modify, maintain, repair and replace protective relay systems on all of the facilities identified in Appendix A, in accordance with sound engineering judgment, WSCC and NERC criteria and Good Utility Practice.

8.2.4 **Non-ISO Controlled Grid Critical Protective Systems**. Each Participating TO may alter the settings and functionality of protective relay systems and

Remedial Action Schemes that have not been designated as ISO Controlled Grid Critical Protective Systems without the consent of the ISO, provided that such changes do not reduce the normal or emergency rating of a facility identified in the ISO Register. If the facility rating will be reduced, the Participating TO shall obtain approval of the ISO prior to making such changes. In addition, the Participating TO shall promptly report to the ISO any facility rating increases that result from any changes to its protective relay settings or Remedial Action Schemes.

8.2.5 **Consistency.** The ISO shall develop in consultation with Participating TOs a consistent approach to protective system design and philosophy throughout the ISO Controlled Grid to the extent that it is practical and cost effective.

9. SYSTEM EMERGENCIES

9.1. ISO Management of Emergencies.

The ISO shall manage a System Emergency pursuant to the provisions of Section 2.3.2 of the ISO Tariff. The ISO may carry out unannounced tests of System Emergency procedures pursuant to the ISO Tariff.

9.2. Management of Emergencies by Participating TOs.

9.2.1 **ISO Orders.** In the event of a System Emergency, the Participating TOs shall comply with all directions from the ISO regarding the management and alleviation of the System Emergency unless such compliance would impair the health or safety of personnel or the general public.

9.2.2 **Communication.** During a System Emergency, the ISO and Participating TOs shall communicate through their respective control centers, in accordance with the Operating Procedures.

9.3. System Emergency Reports: TO Obligations.

9.3.1 **Records.** Pursuant to Section 17, each Participating TO shall maintain appropriate records pertaining to a System Emergency.

9.3.2 **Review.** Each Participating TO shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3 of the ISO Tariff and Section 17 of this Agreement.

9.4. Sanctions.

In the event of a major Outage that affects at least 10 percent of the customers of an entity providing local distribution service, the ISO may order a Participating TO to pay appropriate sanctions, as filed with and approved by FERC in accordance with Section 12.3, if the ISO finds that the operation and maintenance practices of the Participating TO, with respect to its transmission lines and associated facilities that it has placed under the ISO's Operational Control, prolonged the response time or was responsible for the Outage.

10. ISO CONTROLLED GRID ACCESS AND INTERCONNECTION

10.1. ISO Controlled Grid Access and Services.

10.1.1 **Access.** The ISO shall respond to requests from the Participating TOs and other Market Participants for access to the ISO Controlled Grid. All Participating TOs who have Eligible Customers connected to their transmission or distribution facilities that do not form part of the ISO Controlled Grid shall ensure open and non-discriminatory access to those facilities for those Eligible Customers through the implementation of an open access tariff, provided that a Participating TO shall only be required to ensure open access to those facilities for End-Use Customers to the extent it is required by applicable law to do so or pursuant to a voluntary offer to do so.

10.2. Interconnection.

10.2.1 **Obligation to Interconnect.** The Parties shall be obligated to allow interconnection to the ISO Controlled Grid in a non-discriminatory manner, subject to the conditions specified in this Section 10 and the applicable legal requirements.

10.2.2 **Standards.** All Interconnections shall be designed and built in accordance with Good Utility Practice, all Applicable Reliability Criteria, and applicable statutes and regulations.

10.2.3 **System Upgrades**. A Participating TO shall be entitled to require a entity requesting Interconnection to pay for all necessary system reliability upgrades on its side of the Interconnection and on the ISO Controlled Grid, as well as for all required studies, inspection and testing, to the extent permitted by FERC policy. The entity requesting Interconnection shall be required to execute an Interconnection Agreement in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff, and must comply with all of their provisions, including provisions related to creditworthiness and payment for Facility Studies.

10.2.4 A Local Furnishing Participating TO shall not be obligated to construct or expand interconnection facilities or system upgrades unless and until the conditions stated in Section 4.1.2 hereof have been satisfied.

10.3. Interconnections Responsibilities.

10.3.1 **Applicability**. The provisions of this Section 10.3 shall apply only to those facilities over which a Participating TO has legal authority to effectuate proposed interconnections to the ISO Controlled Grid. Where a Participating TO does not have the legal authority to compel interconnection, the Participating TO's obligations with respect to interconnections shall be as set forth in its Commission approved TO Tariff which shall contain an obligation for the Participating TO, at a minimum, to submit or assist in the submission of, expansion and/or interconnection requests from third parties to the appropriate bodies of a project pursuant to the individual project agreements to the full extent allowed by such agreements and the applicable laws and regulations.

10.3.2 **Technical Standards**. Each Participating TO shall develop technical standards for the design, construction, inspection, and testing applicable to proposed Interconnections of Load and/or Generation Unit and apparatus to that part of the ISO Controlled Grid Facilities owned by the Participating TO. Such standards shall be consistent with Applicable Reliability Criteria and shall be developed in consultation with the ISO. The Participating TO shall periodically review and revise its criteria to ensure compliance with Applicable Reliability Criteria.

10.3.3 **Review of Participating TO Technical Standards**. Participating TOs shall provide the ISO with copies of their technical standards for Interconnection developed pursuant to Section 10.3.2 of this Agreement and all amendments so that the ISO can satisfy itself as to their compliance with the Applicable Reliability Criteria. The ISO shall develop consistent Interconnection standards across the ISO Controlled Grid, to the extent possible given the circumstances of each Participating TO, in consultation with Participating TOs. Any differences in Interconnection standards shall be addressed through negotiations and dispute resolution proceedings, as set forth in the ISO Tariff, between the ISO and the Participating TO.

10.3.4 **Notice.** A list of the Interconnection standards and procedures developed by each Participating TO pursuant to Section 10.3.2, including any revisions, shall be made available to the public through the information board (e.g. WEnet or ISO internet website). In addition, the posting will provide information on how to obtain the Interconnection standards and procedures. The Participating TO shall provide these standards to any party, upon request.

10.3.5 **Interconnection.** Each Participating TO and the ISO shall process Interconnection requests in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff. Any differences in the procedures for interconnection contained in the ISO Tariff and the TO Tariff shall be addressed through negotiations and dispute resolution procedures, as set forth in the ISO Tariff, between the ISO and the Participating TO.

10.3.6 **Acceptance of Interconnection Facilities.** The Participating TO shall perform all necessary site inspections, review all relevant equipment tests, and ensure that all necessary agreements have been fully executed prior to accepting Interconnection facilities for operation.

10.3.7 **Collection of Payments.** The Participating TO shall collect all payments owed under any System Impact Study Agreement, Facility Study Agreement or other agreement entered into pursuant to this Section 10.3 or the provisions of the ISO Tariff and its TO Tariff as applicable relating to Interconnection.

10.3.8 **On-Site Inspections**. The ISO may at its own expense accompany a Participating TO during on-site inspections and tests of Interconnections or, by pre-arrangement, may itself inspect Interconnections or perform its own additional inspections and tests.

10.4 Joint Responsibilities.

The Parties shall share with the ISO relevant information about Interconnection requests and coordinate their activities to ensure that all Interconnection requests are processed in a timely, non-discriminatory fashion and that all Interconnections meet the operational and reliability criteria applicable to the ISO Controlled Grid. Subject to Section 26.3 of this Agreement, the ISO shall pass on such information to any Parties who require it to carry out their responsibilities under this Agreement.

11. EXPANSION OF TRANSMISSION FACILITIES

The provisions of Section 3.2 of the ISO Tariff will apply to any expansion or reinforcement of the ISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the ISO.

12. USE AND ADMINISTRATION OF THE ISO CONTROLLED GRID

12.1. Use of the ISO Controlled Grid.

Except as provided in Section 13, use of the ISO Controlled Grid by the

Participating TOs and other Market Participants shall be in accordance with the rates, terms, and conditions established in the ISO Tariff and the Participating TO's Tariff. Pursuant to Section 2.1.2 of the ISO Tariff transmission service shall be provided only to direct access and wholesale customers eligible under state and federal law.

12.2. Administration.

Each Participating TO transfers authority to the ISO to administer the terms and conditions for access to the ISO Controlled Grid and to collect, among other things, Congestion Management revenues, and Wheeling-Through and Wheeling-Out revenues.

12.3. Incentives and Penalty Revenues.

The ISO, in consultation with the Participating TOs, shall develop standards and a mechanism for paying to and collecting from Participating TOs incentives and penalties that may be assessed by the ISO. Such standards and mechanism shall be filed with FERC and shall become effective upon acceptance by FERC.

13. EXISTING AGREEMENTS

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff will apply to the treatment of transmission facilities of a Participating TO under the Operational Control of the ISO which are subject to transmission service rights under Existing Contracts. In addition, the ISO will honor the operating obligations as specified by the Participating TO, pursuant to Section 6.4.2 of this Agreement, including any provision of interconnection, integration, exchange, operating, joint ownership and joint participation agreements, when operating the ISO Controlled Grid.

14. MAINTENANCE STANDARDS

14.1. ISO Determination of Standards.

The ISO shall adopt, in consultation with the Participating TOs through the Maintenance Coordination Committee, standards for the maintenance, inspection, repair, and replacement of transmission facilities under its Operational Control in accordance with Appendix C. These standards, which shall be performance-based or prescriptive or both, will provide for high quality, safe, and reliable service and shall take into account costs, local geography and weather, the Applicable Reliability Criteria, national electric industry practice, sound engineering judgment and experience.

14.2. Existing Standards.

Until such time as the ISO adopts standards pursuant to Section 14.1, the ISO shall measure the performance of Participating TOs in relation to the maintenance, inspection, repair and replacement of transmission facilities by their existing standards. Each Participating TO shall provide the ISO with such information as the ISO shall require to identify such Participating TO's existing maintenance standards and measure its performance against the relevant standards.

14.3. Availability Formula.

14.3.1 **Availability Measure.** The ISO performance-based standards shall be based on the availability measures described in Section 4 of Appendix C of this Agreement.

14.3.2 **Excluded Events.** Scheduled Approved Maintenance Outages and certain Forced Outages will be excluded pursuant to Section 4.2.3 of Appendix C of this Agreement from the calculation of the availability measure.

14.3.3 **Availability Measure Target.** The Maintenance Coordination Committee and each Participating TO shall jointly develop for the Participating TO an availability measure target, which may be defined by a range. The target will be based on prior Participating TO performance developed in accordance with Section 4 of Appendix C of this Agreement and national benchmarks.

14.3.4 **Calculation of Availability Measure.** The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will determine the availability measure in accordance with Section 4 of Appendix C of this Agreement.

14.3.5 **Compliance with Availability Measure Target.** The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.3.6 **Public Record.** The Participating TO's annual availability measure calculation and the associated availability measure data shall be made available to the public.

14.4. Revisions to Standards.

The ISO shall periodically review with the Participating TOs the standards and incentives implemented pursuant to this Section 14 and, through the Maintenance Coordination Committee process, shall modify these standards and incentives as necessary.

14.5. Incentives and Penalties.

The ISO shall, subject to regulatory approval, develop incentive programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the availability performance imposes demonstrable costs or results in demonstrable benefits for Market Participants.

15. DISPUTE RESOLUTION

In the event any dispute regarding the terms and conditions of this Agreement is not settled, the Parties shall follow the ISO ADR Procedure set forth in Section 13 of the ISO Tariff. The specific references in this Agreement to alternative dispute resolution procedures shall not be interpreted to limit the Parties' rights and obligations to invoke dispute resolution procedures pursuant to this Section 15.

16. BILLING AND PAYMENT

16.1 Application of ISO Tariff

The ISO and Participating TOs shall comply with the billing and payment provisions set forth in Section 11 of the ISO Tariff.

16.2 Refund Obligation

Each Participating TO, whether or not it is subject to the rate jurisdiction of the FERC under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its TO Tariff and do all other things required of a Participating TO to implement any FERC order related to the ISO Tariff, including any FERC order that requires the ISO to make payment adjustments or pay refunds to, or receive prior period overpayments from, any Participating TO. All such refunds and adjustments shall be made, and all other actions taken, in accordance with the ISO Tariff, unless the applicable FERC order requires otherwise.

17. RECORDS AND INFORMATION SHARING

17.1. Records Relevant to Operation of ISO Controlled Grid.

The ISO shall keep such records as may be necessary for the efficient operation of the ISO Controlled Grid and shall make appropriate records available to a Participating TO, upon request. The ISO shall maintain for not less than five (5) years: (1) a record of its operating orders and (2) a record of the contents of, and changes to, the ISO Register.

17.2. Participating TO Records and Information Sharing.

17.2.1 **Existing Standards**. Each Participating TO shall provide to the ISO in a format and at the time to be established by the ISO in coordination with the Participating TO, the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control in effect as of the date it executes this Agreement.

17.2.2 **Records**. Each Participating TO shall provide and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control and shall maintain records of all inspections, maintenance, replacement, and repairs performed on such facilities, which records shall be shared with the ISO under reasonable guidelines and procedures to be specified by the ISO.

17.2.3 **Required Reports.** Pursuant to this Agreement and the provisions of the ISO Tariff, each Participating TO shall provide to the ISO timely information, notices, or reports regarding matters of mutual concern, including:

i. System Emergencies, Forced Outages and other incidents affecting the ISO Controlled Grid;

ii. Maintenance Outage requests, including yearly forecasts required by Section 2.3.3.5 of the ISO Tariff;

iii. System Planning Studies, including studies prepared in connection with Interconnections or any transmission facility enhancement or expansion; and

iv. Compliance with the inspection, maintenance, repair, and replacement standards established under Section 14.

17.2.4 **Other Reports.** The ISO may, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO within a reasonable time and in a form to be specified by the ISO.

17.2.5 **Other Market Participant Information.** At the request of the ISO, a Participating TO shall provide the ISO with non-confidential information obtained by the Participating TO from other Market Participants pursuant to contracts between the Participating TO and such other Market Participants. Such requests shall be limited to information that is reasonably necessary for the operation of the ISO Controlled Grid.

17.3. ISO System Studies and Operating Procedures.

17.3.1 **System Studies and Grid Stability Analyses.** The ISO, in coordination with Participating TOs, shall perform system operating studies or grid stability analyses to evaluate forecasted changes in grid conditions that could affect its ability to ensure compliance with the Applicable Reliability Criteria. The results and reports from such studies shall be exchanged between the ISO and the Participating TOs. Study results and conclusions shall generally be assessed annually, and shall be updated as necessary, based on changing grid and local area conditions.

17.3.2 **Grid Conditions Affecting Regulations, Permits and Licenses.** The ISO shall promulgate and maintain Operating Procedures to ensure that impaired or potentially degraded grid conditions are assessed and immediately communicated to the Participating TOs for operability determinations required by applicable regulations, permits or licenses, such as NRC operating licenses for nuclear generating units.

17.4. Significant Incident.

17.4.1 Risk of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware of the risk of significant incident, including extreme temperatures, storms, floods, fires, earthquakes, earth slides, sabotage, civil unrest, equipment outage limitations, etc., that affect the ISO Controlled Grid. The Parties shall provide information that the reporting Party reasonably deems appropriate and necessary for the other Parties to prepare for the occurrence, in accordance with Good Utility Practice.

17.4.2 Occurrence of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware that a significant incident affecting the ISO Controlled Grid has occurred. Subsequent to notification, each Party shall make available to the ISO all relevant data related to the occurrence of the significant incident. Such data shall be sufficient to accommodate any reporting or analysis necessary for the Parties to meet their obligations under this Agreement.

17.5. Review of Information and Record-Related Policies.

The ISO shall review the requirements of this Section 17 annually and shall, consistent with reliability and regulatory needs, seek to standardize reasonable record keeping, reporting, and information sharing requirements.

18. GRANTING RIGHTS-OF-ACCESS TO FACILITIES

18.1. Equipment Installation.

In order to meet its obligations under this Agreement, a Party that owns, rents, or leases equipment (the equipment owner) may require installation of such equipment on property owned by another Party (the property owner), provided that the property is being used for an electric utility purpose and that the property owner shall not be required to do so if it would thereby be prevented from performing its own obligations or exercising its rights under this Agreement.

18.1.1 **Free Access.** The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, repair, upgrading, or removal for the purposes of this Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.

18.1.2 **Notice.** The equipment owner (whether ISO or Participating TO) shall provide reasonable notice to the property owner when requesting access for site assessment, coordinating equipment installation, or other relevant purposes.

18.1.3 **Removal of Installed Equipment.** Following reasonable notice, the equipment owner shall be required, at its own expense, to remove or relocate equipment, at the request of the property owner, provided that the equipment owner shall not be required to do so if it would thereby be prevented from performing its obligations or exercising its rights under this Agreement.

18.1.4 **Costs.** The equipment owner shall repair at its own expense any property damage it causes in exercising its rights and shall reimburse the property owner for any other costs that it is required to incur to accommodate the equipment owner's exercise of its rights under this Section 18.1.

18.2. Rights to Assets.

The Parties shall not interfere with each other's assets, without prior agreement.

18.3. Inspection of Facilities.

In order to meet their respective obligations under this Agreement, any Party may view or inspect facilities owned by another Party. Provided that reasonable notice is given, a Party shall not unreasonably deny access to relevant facilities for viewing or inspection by the requesting Party.

19. [INTENTIONALLY LEFT BLANK]

20. TRAINING

20.1. Staffing and Training to Meet Obligations.

Each Party shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. Each Party shall employ (or cause to be employed) only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct contained in the ISO Bylaws and approved by FERC.

20.2. Technical Training.

The ISO and the Participating TOs shall respond to reasonable requests for support and provide relevant technical training to each other's employees to support the safe, reliable, and efficient operation of the ISO Controlled Grid and to comply with any NERC or WSCC operator certification or training requirements. Examples of such technical training include, but are not limited to: (1) the theory or operation of new or modified equipment (e.g., control systems, remedial action schemes, protective relays); (2) computer and applicator programs; and (3) ISO (or Participating TO) requirements. The Parties shall enter into agreements regarding the timing, term, locations, and cost allocation for the training.

21. OTHER SUPPORT SYSTEMS REQUIREMENTS

21.1. Related Systems.

The Parties shall each own, maintain, and operate equipment, other than those facilities described in the ISO Register, which is necessary to meet their specific obligations under this Agreement.

21.2. Lease or Rental of Equipment by the ISO.

Under certain circumstances, it may be prudent for the ISO to lease or rent equipment owned by a Participating TO, (e.g., EMS/SCADA, metering, telemetry, and communications systems), instead of installing its own equipment. In such case, the ISO and the Participating TO shall mutually determine whether the ISO shall lease or rent the Participating TO's equipment. The ISO and the Participating TO shall enter into a written agreement specifying all the terms and conditions governing the lease or rental, including its term, equipment specifications, maintenance, availability, liability, interference mitigation, and payment terms.

22. LIABILITY

22.1. Liability for Damages.

Except as provided for in Section 13.3.14 of the ISO Tariff and subject to Section 22.4 no Party to this Agreement shall be liable to any other Party for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this Agreement except to the extent that its negligent performance of this Agreement (including intentional breach) results directly in physical damage to property owned, operated by or under the operational control of any of the other Parties or in the death or injury of any person.

22.2. Exclusion of Certain Types of Loss.

No Party shall be liable to any other party under any circumstances whatsoever for any consequential or indirect financial loss (including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill) resulting from physical damage to property for which a party may be liable under Section 22.1.

22.3. ISO's Insurance.

The ISO shall maintain insurance policies covering part or all of its liability under this Agreement with such insurance companies and containing such policy limits and deductible amounts as shall be determined by the ISO Governing Board from time to time. The ISO shall provide all Participating TOs with details of all insurance policies maintained by it pursuant to this Section 22 and shall have them named as additional insureds to the extent of their insurable interest.

22.4. Participating TOs Indemnity.

Each Participating TO shall indemnify the ISO and hold it harmless against all losses, damages, claims, liability, costs or expenses (including legal expenses) arising from third party claims due to any act or omission of that Participating TO except to the extent that they result from intentional wrongdoing or negligence on the part of the ISO or of its officers, directors or employees. The ISO shall give written notice of any third party claims against which it is entitled to be indemnified under this Section to the Participating TOs concerned promptly after becoming aware of them. The Participating TOs who have acknowledged their obligation to provide a full indemnity shall be entitled to control any litigation in relation to such third party claims (including settlement and other negotiations) and the ISO shall, subject to its right to be indemnified against any resulting costs, cooperate fully with the Participating TOs in defense of such claims.

23. UNCONTROLLABLE FORCES

23.1. Occurrences of Uncontrollable Forces.

An Uncontrollable Force means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence. No Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to the occurrence of an Uncontrollable Force.

23.2. Obligations In the Event of an Uncontrollable Force.

In the event of the occurrence of an Uncontrollable Force, which prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Parties of such Uncontrollable Force with such notice to be confirmed in writing as soon as reasonably practicable; (2) not be entitled to suspend performance of its obligations under this Agreement to any greater extent or for any longer duration than is required by the Uncontrollable Force; (3) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligations hereunder; (4) keep the other Parties apprised of such efforts on a continual basis; and (5) provide written notice of the resumption of performance hereunder. Notwithstanding any of the foregoing, the settlement of any strike, lockout, or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the Party to this Agreement involved in such strike, lockout, or labor dispute and the requirement that a Party must use its best efforts to remedy the cause of the Uncontrollable Force and/or mitigate its effects and resume full performance hereunder shall not apply to strikes, lockouts, or labor disputes.

24. ASSIGNMENTS AND CONVEYANCES

No Party may assign its rights or transfer its obligations under this Agreement except, in the case of a Participating TO, pursuant to Section 4.4.1.

25. ISO ENFORCEMENT

In addition to its other rights and remedies under this Agreement, the ISO may if it sees fit initiate regulatory proceedings seeking the imposition of sanctions against any Participating TO who commits a material breach of its obligations under this Agreement.

26. MISCELLANEOUS

26.1. Notices.

Any notice, demand, or request in accordance with this Agreement, unless otherwise provided in this Agreement, shall be in writing and shall be deemed properly served, given, or made: (1) upon delivery if delivered in person; (2) five (5) days after deposit in the mail, if sent by first class United States mail, postage prepaid; (3) upon receipt of confirmation by return electronic facsimile if sent by facsimile; or (4) upon delivery if delivered by prepaid commercial courier service. Any Party may at any time, by notice to the other Parties, change the designation or address of the person specified to receive notice on its behalf in Appendix F. Such changes to Appendix F shall not constitute an amendment to this Agreement. Any notice of a routine character in connection with service under this Agreement or in connection with the operation of facilities shall be given in such a manner as the Parties may determine from time to time, unless otherwise provided in this Agreement.

26.2. Non-Waiver.

Any waiver at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

26.3. Confidentiality.

26.3.1 **ISO**. The ISO shall maintain the confidentiality of all of the documents, data, and information provided to it by any other Party that are treated as confidential or commercially sensitive under the confidentiality provisions of the ISO Tariff; provided, however, that the ISO shall not keep confidential: (1) information that is explicitly subject to data exchange through WEnet or the ISO internet website pursuant to Section 6 of the ISO Tariff; (2) information that the ISO or the Party providing the information is required to disclose pursuant to this Agreement, the ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) the information becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this

Agreement).

26.3.2 **Other Parties**. No Party shall have a right hereunder to receive from the ISO or to review any documents, data or other information of another Party to the extent such documents, data or information are required to be kept confidential in accordance with Section 26.3.1 above, provided, however, that a Party may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose any individual Party's confidential data or information.

26.3.3 **Disclosure**. Notwithstanding anything in this Section 26.3 to the contrary, if the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 26.3, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify the affected Party or Parties of the requirement and the terms thereof. The affected Party or Parties may, at their sole discretion and own costs, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Party or Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Parties to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

26.4. Third Party Beneficiaries.

The Parties do not intend to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, covenant, obligation, or undertaking established hereunder.

26.5. Relationship of the Parties.

The covenants, obligations, rights, and liabilities of the Parties under this Agreement are intended to be several and not joint or collective, and nothing contained herein shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation, or liability on, or with regard to, any of the Parties. Each Party shall be individually responsible for its own covenants, obligations, and liabilities under this Agreement. No Party or group of Parties shall be under the control of or shall be deemed to control any other Party or Parties. No Party shall be the agent of or have the right or power to bind any other Party without its written consent, except as expressly provided for in this Agreement.

26.6. Titles.

The captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

26.7. Severability.

If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this

Agreement and their application shall not be affected thereby, but shall remain in force and effect and the parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

26.8. Preservation of Obligations.

Upon termination of this Agreement, all unsatisfied obligations of each Party shall be preserved until satisfied.

26.9. Governing Law.

This Agreement shall be interpreted, governed by and construed under the laws of the State of California, without regard to the principles of conflict of laws thereof, or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

26.10. Construction of Agreement.

Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against any Party, but shall be construed in a manner that most accurately reflects the purpose of this Agreement and the nature of the rights and obligations of the Parties with respect to the matter being construed.

26.11. Amendment.

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.

26.12. Appendices Incorporated.

The several appendices to this Agreement, as may be revised from time to time, are attached to this Agreement and are incorporated by reference as if herein fully set forth.

26.13. Counterparts.

This Agreement may be executed in one or more counterparts, which may be executed at different times. Each counterpart, which shall include applicable individual Appendices A, B, C, D and E shall constitute an original but all such counterparts together shall constitute one and the same instrument.

27. SIGNATURE PAGE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

California Independent System Operator Corporation has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 21st day of November, 20 02 and thereby incorporates the following Appendices in this Agreement:

Appendices A

Appendices B

Appendix C

Appendix D

Appendices E

Appendix F

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
151 Blue Ravine Road
Folsom, California 95630

by: Terry M. Winter

Terry M. Winter
President and Chief Executive Officer

28. SIGNATURE PAGE

PACIFIC GAS AND ELECTRIC COMPANY

Pacific Gas and Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 20th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (PG&E)

Appendix B (PG&E)

Appendix C

Appendix D

Appendix E (Diablo Canyon)

Appendix F

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street
San Francisco, California 94105

by: Karen A. Tomcala

Karen A. Tomcala
Vice President, Regulatory Relations

29. SIGNATURE PAGE

SAN DIEGO GAS & ELECTRIC COMPANY

San Diego Gas & Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 15th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (SDG&E)

Appendix B (SDG&E)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court
San Diego, California 92123

by: ______________________

James Avery
Senior Vice President of San Diego Gas & Electric

30. SIGNATURE PAGE

SOUTHERN CALIFORNIA EDISON COMPANY

Southern California Edison Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 19th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Edison)

Appendix B (Edison)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

by: Richard M Rosenblum

Richard M. Rosenblum
Senior Vice President, Transmission & Distribution

31. SIGNATURE PAGE

CITY OF VERNON

CITY OF VERNON has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 20th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Vernon)

Appendix B (Vernon)

Appendix C

Appendix D

Appendix E

Appendix F

CITY OF VERNON

By: Leonis C. Malburg
LEONIS C. MALBURG, Mayor

ATTEST:

BRUCE V. MALKENHORST, City Clerk

APPROVED AS TO FORM:

Eduardo Olivo
EDUARDO OLIVO, City Attorney

32. SIGNATURE PAGE

CITY OF ANAHEIM

CITY OF ANAHEIM has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 18th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Anaheim)

Appendix B (Anaheim)

Appendix C

Appendix D

Appendix F

CITY OF ANAHEIM

By: Marcie L Edwards
Marcie L. Edwards
Public Utilities General Manager

ATTEST:

Sheryll Schroeder

APPROVED AS TO FORM:
JACK L. WHITE, CITY ATTORNEY

BY Lucina Lea Moses 11/14/02
LUCINA LEA MOSES
ASSISTANT CITY ATTORNEY

APPROVED AS TO FORM:

____

33. SIGNATURE PAGE

CITY OF AZUSA

CITY OF AZUSA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this __19th__ day of __November__, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Azusa)

Appendix B (Azusa)

Appendix C

Appendix D

Appendix F

CITY OF AZUSA

By:____________________
Cristina C. Madrid
Mayor

34. SIGNATURE PAGE

CITY OF BANNING

CITY OF BANNING has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 18th day of Nov., 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Banning)

Appendix C

Appendix D

Appendix F

CITY OF BANNING

By: John Hunt
John Hunt
Mayor

ATTEST:

Marie A. Calderon

APPROVED AS TO FORM:

35. SIGNATURE PAGE

CITY OF RIVERSIDE

CITY OF RIVERSIDE has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 19th day of November, 2002 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Riverside)

Appendix B (Riverside)

Appendix C

Appendix D

Appendix F

CITY OF RIVERSIDE
3900 Main Street, 4th Floor
Riverside, California 92522

By: George A. Caravalho
George A. Caravalho, City Manager

ATTEST:

Colleen J. Nicol
City Clerk

APPROVED AS TO FORM:

Susan M. Sudeski
Supervising Deputy City Attorney

TRANSMISSION CONTROL AGREEMENT

APPENDIX A

Facilities and Entitlements

(The Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO were submitted by the ISO on behalf of the Transmission Owners on March 31, 1997– any modifications are attached as follows)

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

(submitted by the ISO on behalf of Pacific Gas and Electric Company Transmission Owner)

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted by the ISO on behalf of PG&E on March 31, 1997 are amended as follows.

Item 1: Port of Oakland 115 kV Facilities

Operation Control of the transmission facilities, shown on operating diagram, East Bay Region (East Bay Division), Sheet No. 1, serving the Port of Oakland and Davis 115 kV (USN) is not to be transferred to the ISO. These are special facilities funded by and connected solely to a customer's substation and their operation is not necessary for control by the ISO pursuant to the specifications of Section 4.1.1 of the TCA.

As of the date of execution of the TCA, the California ISO and PG&E are discussing further modifications to the diagrams of transmission lines and facilities placed under the control of the ISO. A new version of the diagrams is to be filed with FERC prior to April 1, 1998. This subsequent version of the diagrams will reflect all modifications (including those described herein).

APPENDIX A2

List of Entitlements Being Placed under ISO Operational Control

(Includes only those where PG&E is a service rights-holder)

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Pacific Power & Light, SCE, SDG&E	Transmission Use Agreement - PP&L Rate Schedule with FERC	Transmission	Upon 40 years beginning approx. 1968	
2.	SCE, SDG&E	California Power Pool - PG&E Rate Schedule FERC No. 27	Power pool	Terminated	5/6/97
3.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement - PG&E Rate Schedule FERC No. 38	Transmission	4/1/2007	Both entitlement and encumbrance.
4.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan - PG&E Rate Schedule FERC No. 183	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
5.	TANC	Coordinated Operations Agreement - PG&E Rate Schedule FERC No. 146	Interconnection, scheduling, transmission	1/1/2043	Both entitlement and encumbrance.
6.	WAPA	EHV Transmission Agreement - Contract No. 2947A - PG&E Rate Schedule FERC No. 35	Transmission	1/1/2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.	Both entitlement and encumbrance.
7.	Various - See Attachment A	Western Systems Power Pool Agreement - WSPP Rate Schedule FERC No. 1	Power sales, transmission	Upon WSPP expiration	Both entitlement and encumbrance.
8.	Vernon (City of)	Transmission Service Exchange Agreement - PG&E Rate Schedule FERC No. 148	Transmission	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for service on COTP

Supplement To PG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system[1] Pacific Gas and Electric Company (PG&E) is placing under the California Independent System Operator's Operational Control will meet the Applicable Reliability Criteria in 1998,[2] except (1) for the transmission facilities comprising Path 15, which do not meet the Western Systems Coordinating Council's (WSCC) Reliability Criteria for Transmission Planning with a simultaneous outage of the Los Banos-Gates and Los Banos-Midway 500 kV lines (for south-to-north power flow exceeding 2500 MW on Path 15),[3] and (2) with respect to potential problems identified in PG&E's annual assessment of its reliability performance in accordance with Applicable Reliability Criteria, performed with participation from the ISO and other stakeholders; as a result of this process, PG&E has been developing solutions to mitigate the identified potential problems and submitting them to the ISO for approval.

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Based upon PG&E's substation and system load forecasts for study year 1998, historically typical generation dispatch and the Applicable Reliability Criteria, including the current applicable WSCC Reliability Criteria for Transmission Planning issued in March 1997, the PG&E Local Reliability as stated in the 1997 PG&E Transmission Planning Handbook Criteria (submitted to the California ISO Transmission Planning, in writing, on October 20, 1997), and the NERC Reliability Performance Criteria in effect at the time PG&E was assessing its system (as of June 1, 1997). PG&E may not meet the WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.

[3] The ISO will operate Path 15 so as to maintain system reliability. In accepting this notice from PG&E, the ISO agrees to work with PG&E and the WSCC to achieve a resolution respecting the WSCC long-term path rating limit for Path 15, consistent with WSCC requirements. Pending any revision to the WSCC long-term path rating limit for Path 15, the ISO will continue to operate Path 15 at the existing WSCC long-term path rating limit unless, in the judgment of the ISO:

> (a) the operating limit must be reduced on a short-term (e.g., seasonal) basis to maintain system reliability, taking into account factors such as the WSCC guidelines, determination of credible outages and the Operating Capability Study Group (OCSG) study process; or
>
> (b) the operating limit must be reduced on a real-time basis to maintain system reliability.

In determining whether the operating limit of Path 15 must be changed to maintain system reliability, the ISO shall, to the extent possible, work with the WSCC and the PTOs to reach consensus as to any new interim operating limit.

Pursuant to Section 4.1.5(i), PG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of PG&E utility service pursuant to AB 1890. However, PG&E can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from PG&E's rights pursuant to its physical ownership and operation of transmission facilities.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
1.	California Companies Pacific Intertie Agreement (CCPIA)	PG&E, SDG&E	40	July 31, 2007	• 43% of the California Companies entitlements on the Pacific Intertie.
2.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	303	2040 or sooner by mutual agreement of the parties.	• Edison owns 50% of the D-C transmission facility. (Per CCPIA, this ownership is part of the California Companies entitlements on the Pacific Intertie).
3.	PP&L Agreement	PP&L, PG&E, SDG&E		2008	• California Companies are entitled to use the entire capacity on the PP&L 500kV transmission line from Malin to Indian Spring for the term of the agreement. Per CCPIA Edison is entitled to 43% of the capacity available on the Pacific Intertie.
4.	WAPA Contract with California Companies for Extra High Voltage Transmission and Exchange Service	WAPA, PG&E, SDG&E	37	January 1, 2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.	• WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to CCPIA Parties.
5.	Los Angeles-Edison Exchange Agreement	LADWP	219	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
6.	Coordinated Operations Agreement	PG&E, SDG&E, and COTP Participants	270.7	January 1, 2043	• The allocation of Available Scheduling Capability between COTP parties and PACI parties is calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
7.	Pasadena-Edison 230-KV Interconnection and Transmission Agreement	Pasadena	55	2011	• Goodrich-Gould and Goodrich-Laguna Bell 230 kV transmission line interconnect Edison's system with Pasadena's system at Pasadena's Goodrich Substation. Lines have been re-configured from arrangement shown in contract. • Edison maintains and operates Goodrich 230 kV Substation.
8.	[Terminated – Not Available]				
9.	Victorville-Lugo Interconnection Agreement	LADWP	51	2019 or sooner by mutual agreement	• 1950 MW towards Edison, 900 MW towards LADWP. Transfer capability of the interconnection is established through joint technical studies.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
10.	City-Edison Sylmar Interconnection Agreement	LADWP	307	On 5 years notice by either party any time after the termination of the City-Edison Pacific Intertie DC Transmission Facilities Agreement.	• Sylmar-Pardee #1&2, Sylmar-Gould and Sylmar-Eagle Rock 230 kV transmission line interconnections at Sylmar including circuit breakers and busses. Lines have been re-configured from arrangement described in contract. • Edison owns one of the two regulating transformers at Sylmar.
11.	City-Edison Owens Valley Interconnection and interchange Agreement	LADWP	50	On 12 months notice by either party.	• At the request of either party and by mutual agreement, LADWP's and Edison's respective systems interconnected at LADWP's Haiwee 34.5 kV Substation, may be operated in parallel, which normally operates open at Haiwee.
12.	City-Edison 400,000 kVA Interconnection Agreement (Velasco)	LADWP	215	On 3 year written notice by either party.	• Edison's portion of the normally open Laguna Bell-Velasco 230 kV transmission line from Laguna Bell to the point where ownership changes.
13.	Edison-Los Angeles Inyo Interconnection Agreement	LADWP	306	On 5 year advance written notice by either party or by mutual agreement.	• Inyo 230/115 kV Substation, Inyo Phase Shifter, Control-Inyo 115 kV transmission line and 230 kV Tap to LADWP's Owens Gorge-Rinaldi 230 kV transmission line.
14.	Edison-Los Angeles Sepulveda Canyon Power Plant Transmission Service Agreement	LADWP	280	Termination of Sepulveda Canyon Power Plant Interconnection Agreement or sooner by either party giving a one year notice.	• 9 MW of transmission service from the high voltage leads of Sepulveda Canyon Power Plant to the 230 kV bus at Sylmar.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
15.	[Terminated a/o March 26, 2001 – Not Available]				
16.	Amended and Restated IID-Edison Mirage 230 kV Interconnection Agreement	IID	314	On one year notice but not prior to the termination date of the IID-Edison Transmission Service Agreement.	• Edison's interconnection with IID at Mirage and the point of interconnection on the Devers - Coachella Valley line.
17.	IID Edison Transmission Service Agreement for Alternative Resources	IID	268	Earlier of Dec 31, 2015, or the termination date of the last Plant Connection Agreement.	• Transmission Service on IID's 230 kV system to transmit the output of QFs resources to Edison's system, via Mirage Substation.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
18.	Four Corners Principles of Interconnected Operation	APS, SRP, EPE, PSNM, TGE	47.0	None	• Generation principles for emergency service. • Edison's facility at Four Corners includes its portion of the Eldorado -Moenkopi from Eldorado to CA/NV boarder of the Eldorado-Moenkopi -Four Corners 500 kV transmission line. • Edison can separate its wholly-owned facilities from parallel operation with others under abnormal operating conditions without prior notice. • Edison can separate its wholly-owned facilities from parallel operation with others for maintenance on reasonable advance notice (see Co-tenancy Agreement for facilities). • Edison has the right to schedule emergency service from each party.
19.	Four Corners Project Co-Tenancy Agreement and Operating Agreement	APS, SRP, EPE, PSNM, TGE	47.2	2016	• Edison has co-tenancy ownership of 32% in the Four Corners 500 kV switchyard, 12% in the 345 kV switchyard and 48% in the 345/500 kV bus-tie transformer bank. • Edison has rights to sufficient capacity in the switchyards and bus-tie transformer bank to permit its entitlement to Four-Corners Project power and energy to be delivered to the point where the Eldorado-Moenkopi-Four Corners transmission line connects to the Four Corners 500 kV Switchyard. • Edison may use any unused capacity in the switchyard for any purpose, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership of the requesting co-owners.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
20.	Navajo Interconnection Principles	USA, APS, SRP, NPC, LADWP, TGE	76	None	• Generation principles for emergency service.
21	Edison - Navajo Transmission Agreement	USA, APS, SRP, NPC, LADWP, TGE	264	5/21/23	• In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency transmission service without a charge. The amount of service provided is proportional to each parties' entitlement to the total capability of the transmission system described above.
22.	ANPP High Voltage Switchyard Agreement	APS, SRP, PSNM, EPE, SCPPA, LADWP	320	2031	• Edison has 21.77% undivided ownership interest as a tenant-in-common in the ANPP High Voltage Switchyard. • Edison has rights to transmit through the ANPP High Voltage Switchyard up to its 15.8% share of generation from ANPP, or a substitute equal amount, plus any other generation up to the extent of its transmission rights in the Palo Verde-Devers 500 kV Transmission Line • Edison has additional rights to use any unused capacity in the ANPP High Voltage Switchyard, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
23.	[See Eldorado System Conveyance and Cotenancy Agreement (Line No. 26)]				
24.	Mutual Assistance Transmission Agreement	IID, APS, SDG&E	174	On 2034 or sooner by mutual agreement of the parties.	• In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
25.	Midway Interconnection	PG&E	309	July, 1, 2007	• Edison's share of 500 kV Midway-Vincent transmission system: – Midway-Vincent #1 – Midway-Vincent #2 – Midway-Vincent #3 from Vincent Substation to mile 53, Tower 1
26.	Amended and Restated Eldorado System Conveyance and Co-Tenancy	NPC, SRP, LADWP	424	July 1, 2006	• Edison's share of Eldorado System Components: • Eldorado Substation: Edison Capacity Entitlement = Eldorado Substation Capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]; • Mohave Switchyard: Edison Capacity Entitlement = 884 MW; • Eldorado – Mohave 500 kV line: (Edison Capacity Entitlement – Eldorado – Mohave 500 kV line capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]); • Eldorado – Mead 230 kV Line Nos. 1 & 2: (Edison Capacity Entitlement = Eldorado – Mead 230 kV Line No. 1 &2 capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Capacity Entitlement [158 MW].

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
27.	Sierra Pacific -Edison Silver Peak 55 kV Interconnection Agreement	Sierra Pacific	310	2016 or sooner on 90 days advance notice but not prior to the termination of Edison's Power Purchase Agree. from Chevron.	• Control-Silver Peak A&C 55 kV transmission lines. • Edison's share of the Control-Silver Peak lines is from Control Substation to the CA/NV border.
28.	WAPA-Edison 161 kV Blythe Substation Interconnection Agreement	WAPA	221	September 30, 2007 or sooner by 3 year advanced notice by either party.	• WAPA's Blythe 161 kV Substation, and Edison's Eagle Mountain-Blythe 161 kV transmission line. • Edison may transmit up to 72 MW through WAPA's Blythe Substation, via the Eagle Mountain-Blythe 161 kV transmission line .
29.	SONGS Ownership and Operating Agreements	SDG&E, Anaheim, Riverside	321	None.	• Edison's share of SONGS switchyard with termination of its 230 kV transmission lines: – SONGS - Santiago 1 and 2, – SONGS - Serrano, and – SONGS - Chino 230 kV
30.	District-Edison 1987 Service and Interchange Agreement	MWD	203	September 30, 2017 or on five years notice by either party.	• Transmission is owned by District, but is in ISO control area. If not in use by District, or the United States under existing contracts, District's Transmission Line is available to transmit any electric energy to which Edison may be entitled. • Up to 320 MW is required to supply District's Colorado River Aqueduct pump load. • District's Transmission Line is operated by the District as directed by Edison.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

31.	Edison-Arizona Transmission Agreement	APS	282	On 2016 or later upon negotiation.	• Edison has ownership-like rights to the 500 kV Transmission line from the Four Corners Project to the Arizona-Nevada border. Edison also owns the 500 kV line from Arizona-Nevada border to Edison's Eldorado substation.
32.	Mead Interconnection Agreement	WAPA	308	May 31, 2017	• Edison has rights to transmit its Hoover power • Edison's facilities include Eldorado-Mead 230 kV #1 and 2 transmission lines. • Edison may request additional firm transmission service rights through Mead Substation subject to availability as determined by WAPA.
33.	Power Purchase Contract Between SCE and Midway-Sunset Cogeneration Company.	Midway-Sunset Cogeneration Company.		5/8/09	• 200 MW of capacity through Midway Substation.

Supplement to Edison Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), Southern California Edison Company (Edison) is providing notice its transmission system[1] being placed under the California Independent System Operator's (ISO) Operational Control will meet the Applicable Reliability Criteria in 1998,[2] except as noted in its bulk power program and described herein. Edison's transmission system has been developed in accordance with NERC and WSCC's reliability criteria. WSCC's most recent Log of System Performance Recommendations, dated April 15, 1997, does not show any instances where Edison's transmission system does not meet NERC and WSCC reliability criteria, absent approved exemptions.

Pursuant to Section 4.1.5 (i), Edison does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of Edison's utility service pursuant to AB 1890. However, Edison can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from Edison's rights pursuant to its physical ownership and operation of transmission facilities.

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Edison's most recent assessment is based on Edison's substation and system load forecasts for study year 1998 and criteria in effect as of September 1, 1997. Edison meets WSCC's reliability criteria except for WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high. Assessments of Edison's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2. and under schedules adopted in that process.

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

(submitted by the ISO on behalf of San Diego Gas and Electric Company Transmission Owner)

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted hereby the ISO on behalf of SDG&E are amended as follows.

Item 1: Imperial Valley Switchyard 230kV Breakers Nos. 4132 and 5132 shown in the diagram as non-SDGE facilities should be shown as SDG&E owned. Furthermore, these breakers are being placed under the operational control of the ISO.

APPENDIX A.2: SDG&E'S CONTRACT ENTITLEMENTS

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
66-020	California Companies Pacific Intertie Agreement	Edison, PG&E	20	Subject to FERC's approval and any litigation concerning term, no earlier than July 31, 2007.	7% of the California Companies entitlements on the Pacific Intertie, including delivery rights through SCE's system from Sylmar to SONGS (100 MW); and from SONGS to Sylmar (105 MW); from Midway to SONGS (161 MW); and from SONGS to Midway (109MW).
67-012	Pacific Power & Light Agreement	PP&L, PG&E, Edison		Subject to FERC's acceptance and any litigation concerning term, no earlier than 2008.	California Companies entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. SDG&E is entitled to 7% of the capacity available on the Pacific Intertie.
67-100	WAPA contract with California Companies for Extra High Voltage Transmission and Exchange Service	WAPA, PG&E Edison	37	Subject to FERC's acceptance and any litigation concerning term, no earlier than January 1, 2005. May be extended at negotiated rates.	WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to California Companies Pacific Intertie parties.
92-000	Coordinated Operations Agreement	PG&E, Edison, and COTP participants	270.7	January 1, 2043.	The allocation of Available Scheduling Capability between COTP parties and the Companies Pacific Intertie parties calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	Should a contingency occur in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None.	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey Tap - Mission - Talega (2 lines) - Encina

79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy.
78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by CFE of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031.	The parties are obligated to provide mutual switchyard assistance during emergencies to the extent possible. However, in the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E California Transmission System Participation Agreement	IID		June 24, 2051.	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500 kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E -- 85.64%; and IID -- 14.36%.
78-003	APS-SDG&E Arizona Transmission System Participation Agreement	APS		July 31, 2031.	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS -- 11%; SDG&E - 69%; IID - 20%.

Supplement To SDG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system[1] of San Diego Gas & Electric Company (SDG&E) is placing under the California Independent System Operator's Operational Control meets the Applicable Reliability Criteria,[2] with the following exceptions: (1) SDG&E has not yet re-assessed its system performance for any reliability criteria added or modified by the new North American Electric Reliability Council (NERC) Planning Standards and Guides, released in September, 1997;[3] (2) SDG&E has also not yet re-assessed its system performance for the revised simultaneous generator outage criteria which was approved by the WSCC Board of Trustees on October 27, 1997.[4]

Pursuant to Section 4.1.5(i), SDG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of SDG&E utility service pursuant to AB 1890. However, SDG&E cannot warrant that these right-of-way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from SDG&E's rights, pursuant to its physical ownership and operation of transmission facilities.

---

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Based upon studies with SDG&E's forecast peak 1998 system loads and the Applicable Reliability Criteria, including the WSCC Reliability Criteria for Transmission Planning and WSCC Minimum Operating Reliability Criteria dated March 1997, and the SDG&E Local Reliability Criteria as submitted to the California ISO by letter dated December 15, 1997.

[3] Assessments of SDG&E's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2 and under schedules adopted in that process.

[4] The revised criteria will be cooperatively assessed by SDG&E and the ISO as soon as possible but not later than May 1, 1998. SDG&E also may not meet the WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.

APPENDIX A.2: CITY OF VERNON

TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Vernon (Operating Agent-LA) (7)	Bi-Directional	- MAP Joint Ownership Agreement. - Adelanto Switching Station Interconnection Agreement. - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Coordinating Committee.	81 MW
2. Mead-Phoenix Project (MPP)	SCPPA, MSR, Vernon, SRP, APS (Operating Managers – SRP, Western (DSW)) (7)		- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement - Mead Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Management Committee.	
a) Westwing-Mead		Bi-Directional				28 MW
b) Mead Substation		Bi-Directional				47 MW
c) Mead-Marketplace		Bi-Directional				75 MW

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
3. North to South on COTP South to North on COTP	Vernon, PG&E, TANC, WAPA, City of Shasta Lake, Carmichael Water District, San Juan Suburban Water District, CDWR (Operating Agent-Western (SNR)) (7)		COTP Interim Participation Agreement.		Upon execution of a superseding long-term participation agreement or upon a unanimous decision by the executing parties to terminate this Agreement.	121 MW N-S 92 MW S-N
4. Sylmar-Midway (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	93 MW
5. Sylmar-Laguna Bell - Through midnight December 31, 2002. - After midnight December 31, 2002.	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	 93 MW 60 MW
6. Midway-Laguna Bell (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	60 MW
7. Mead-Laguna Bell	Vernon, Edison	Bi-Directional	Edison-Vernon Mead FTS	207	(2) See Notes	26 MW

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
8. Victorville-Lugo Midpoint-Laguna Bell Note: Service is reduced to 11 MW on 1/1/2003, unless Vernon elects by 10/1/2002 to extend up to an additional 64 MW of service.	Vernon, Edison	Bi-Directional	Edison-Vernon Victorville-Lugo Midpoint FTS	154	(3) See Notes	75 MW
9. Adelanto-Victorville/Lugo Midpoint (4a)	Vernon, Los Angeles	Bi-Directional	Los Angeles-Vernon Adelanto-Victorville/Lugo FTS		(4b) See Notes	75/81 MW (8)
10. NOB-Sylmar-Midway Midway-Sylmar-NOB (6)	Vernon, PG&E	Bi-Directional	Transmission Service Exchange Agreement Between PG&E and the City of Vernon	148	(5) See Notes	93 MW N-S 82 MW S-N

Summary - Details are in each Agreement.

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

Notes:

(1) Contract Termination: Upon termination of Vernon's ownership of a portion of the COTP entitlement.

(2) Contract Termination: Upon termination of Vernon's Hoover Power Sales contract with WAPA; or 12/31/2007 based on proper notice from Vernon to Edison.

(3) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or 12/31/2007 based on proper notice from Vernon to Edison.

(4a) DWP No. 10396.

(4b) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or four years prior written notice by either party.

(5) Contract Termination:

1. This Agreement may be terminated on July 31, 2007:

    A. By PG&E with one year notice to Vernon, if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in DC Line at NOB.

    B. By Vernon, if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.

    C. If the DC Line or COTP facilities are retired.

2. In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

3. Otherwise, the Agreement remains in effect until September 2042.

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

Notes: (continued)

(6) Transfer capability at Sylmar: In accordance with Section 7.2 of the PG&E-Vernon Transmission Service Exchange Agreement and Section 6.1 of the Edison-Vernon Firm Transmission Service Agreement, Vernon receives the following transmission services:

a) 93 MW from NOB to Sylmar.
b) 82 MW from Sylmar to NOB.
c) 93 MW from Sylmar to Laguna Bell (60 MW after midnight December 31, 2002).
d) 93 MW from Laguna Bell to Sylmar (60 MW after midnight December 31, 2002).
e) 60 MW to Sylmar through the regulating transformers.
f) 53 MW from Sylmar through the regulating transformers.
g) 93 MW from Sylmar to Midway, after 12/31/2007.
h) 93 MW from Midway to Sylmar, after 12/31/2007.

(7) For information only.

(8) Effective July 1, 2002, Vernon's Entitlement on the Adelanto-Victorville/Lugo line increases from 75 MW to 81 MW.

APPENDIX A: CITY OF ANAHEIM TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1	IPP-Adelanto Switching Station	Anaheim-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	339 MW
2	Marketplace Substation-Adelanto	Anaheim-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
	Marketplace Substation-McCullough	"	"	"		"	118 MW
3	Westwing-Mead 500 kV	Anaheim-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	47 MW
	Marketplace-Mead 500 kV	"	"	"		"	110 MW
	Mead 500 kV-Mead 230 kV	"	"	"		"	110 MW
	Marketplace Substation-McCullough	"	"	"		"	110 MW
4	Adelanto-Victorville/Lugo	Anaheim-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	110 MW
5	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Base Capacity Transmission Service Agreement		See Note 2	212 MW
6	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Additional Capacity Transmission Service Agreement		See Note 3	127 MW
7	IPP-Mona Substation	Anaheim-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	370 MW
	IPP-Gonder Substation	"	"	"		"	53 MW
8	Nevada-Oregon Border-Sylmar	Anaheim-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	24 MW
9	San Juan-Four Corners	Anaheim-PNM	Bi-directional	Interconnection Agreement – Service Schedule F		See Note 5	50 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Anaheim interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Anaheim interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on termination of Anaheim's ownership interest in San Juan Generating Station Unit 4.

APPENDIX A: CITY OF AZUSA TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC #	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Vernon	Bi-Directional	- MAP Joint Ownership Agreement. - Adelanto Switching Station Interconnection Agreement. - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Coordinating Committee.	19 MW

POINT OF RECEIPT/DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
2. Mead-Phoenix Project (MPP)	SCPPA, MSR, Vernon, SRP, APS		- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement - Mead Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Management Committee.	
a) Westwing-Mead		Bi-Directional				3 MW
b) Mead Substation		Bi-Directional				0 MW
c) Mead-Marketplace		Bi-Directional				3 MW
3. Mead - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Hoover FTS	247.4	(1) See Notes	4 MW
4. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Palo Verde Nuclear Generating Station FTS	247.6	(2) See Notes	4 MW
5. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Pasadena FTS	247.8	(3) See Notes	14 MW

POINT OF RECEIPT - DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
6. Sylmar - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa San Juan Unit 3 FTS	247.29	(4) See Notes	10 MW: January – April; November – December 2003 25 MW: May – October 2003 10 MW: CY 2004 through termination
7. Mead - Rio Hondo	Azusa, Edison	Bi-Directional	Edison-Azusa Sylmar FTS	247.24	(5) See Notes	8 MW
8. Sylmar - NOB	Azusa, Pasadena, Burbank	Bi-Directional	Pacific Intertie Direct Current FTS		(6) See Notes	3MW
9. ANPP (Devers) - Sylmar	Azusa, Los Angeles	Bi-Directional	Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021	(7) See Notes	10 MW
10. Victorville-Lugo - Adelanto	Azusa, Los Angeles	Bi-Directional	Los Angeles - Azusa Adelanto-Victorville/Lugo FTS	DWP No. 10345	(8) See Notes	19 MW
11. Sylmar & Rio Hondo – COB	Azusa, Edison	Uni-Directional	Edison-Azusa Pacific Intertie FTS	247	(9) See Notes	15 MW

Summary- details are in each agreement.

NOTES:

(1) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement or termination of Electric Service Contract, provided that the termination of FTS Agreement shall not occur prior to January 1, 2003.

(2) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement, termination of Azusa's entitlement to PVNGS, or termination of the Arizona Nuclear Power Project Participation, provided that the termination of the FTS Agreement shall not occur prior to January 1, 2003.

(3) Contract Termination:	Upon written agreement between the Parties to terminate the FTS Agreement or termination of City's ownership in San Juan Unit 3, provided that termination of this Transmission Service Agreement shall not occur prior to January 1, 2003.
(4) Contract Termination:	Same as (3)
(5) Contract Termination:	Same as (3)
(6) Contract Termination:	This agreement will be terminated effective September 30, 2009.
(7) Contract Termination:	This agreement shall be terminated upon the earlier of: (i) 2400 hours on December 31, 2023; (ii) by mutual agreement of the Parties; (iii) thirty-six months after Los Angeles has provided written notice that the Agreement is to terminate, provided, however, such notice of termination shall not be given prior to December 31, 2000; or (iv) Azusa may elect to discontinue service under this Agreement by written notice to Los Angeles within sixty days of the mailing date of any subsequent rate for transmission service established under Section 10.3 of the Agreement. If Azusa so elects, this Agreement shall terminate on the last day of the second full month following the mailing date of Azusa's notice.
(8) Contract Termination:	This agreement shall be terminated upon the earlier of: (i) four years prior written notice by either Party, which notice shall not be given before one year after the Date of Firm Operation; (ii)the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville-Lugo transmission line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission line, as such date is defined pursuant to the agreements relating thereto; (v) a date determined pursuant to Section 4.3 of the Agreement; or (vi) a date mutually agreed upon by the Parties.
(9) Contract Termination:	The agreement shall terminate on the earlier of: (i) midnight October 31, 2003; or (ii) at least one year's written notice by City to Edison, provided such notice shall be given no earlier than January 1, 2002.

APPENDIX A: CITY OF BANNING TRANSMISSION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	Marketplace Substation-Adelanto	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		Oct 31, 2030	12 MW
2.	Westwing-Mead-Marketplace 500 kV	Banning-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	3 MW
3.	Marketplace-McCullough 500 kV	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	12 MW 3 MW
4.	ANPP-Sylmar	Banning-LADWP	Bi-directional	ANPP/Sylmar 15 MW Transmission Service Agreement		See Note 1	15 MW
5.	Adelanto-Victorville/Lugo	Banning-LADWP	To Victorville	Adelanto-Victorville/Lugo Firm Transmission Service Agreement		See Note 2	12 MW
6.	Nevada-Oregon Border-Sylmar	Banning-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		Sep 30, 2009	1 MW
7.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Palo Verde Nuclear Generating Station Firm Transmission Service Agreement		See Note 3	3 MW
8.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Sylmar Firm Transmission Service Agreement		See Note 4	5 MW
9.	Mead 230 kV-Devers 115 kV	Banning-SCE	To Devers	Hoover Firm Transmission Service Agreement		See Note 5	2 MW
10.	Devers 500 kV-Devers 115 kV	Banning-SCE	To Devers	1995 San Juan Unit 3 Firm Transmission Service Agreement		See Note 6	15 MW
11.	Devers 500 kV-Devers 115 kV	Banning-SCE	To Devers	1997 Pasadena PSA Firm Transmission Service Agreement		Dec 31, 2003	5 MW
12.	California-Oregon Border-Sylmar	Banning-SCE	To Sylmar	Pacific Intertie Firm Transmission Service Agreement (Seasonal: May – October)		Oct 31, 2003	5 MW

Notes

1. Agreement terminates on: (i) December 31, 2023; or (ii) 36-months notice by LADWP.
2. Agreement terminates on: (i) 4-years written notice by either party; or (ii) the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville/Lugo line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission line, as such date is defined pursuant to the agreements relating thereto.
3. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest in Palo Verde Nuclear Generating Station Unit 2; or (iii) unacceptable FERC modification.
4. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.
5. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of the Electric Service Contract between Western and Banning; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.

APPENDIX A: CITY OF RIVERSIDE TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	IPP-Adelanto Switching Station	Riverside-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	195 MW
2.	Marketplace Substation-Adelanto	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
3.	Westwing-Mead-Marketplace 500 kV	Riverside-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	12 MW
4.	Marketplace-McCullough 500 kV	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		31-Oct-30 31-Oct-30	118 MW 12 MW
5.	Adelanto-Victorville/Lugo	Riverside-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	118 MW
6.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Base Capacity Transmission Service Agreement		See Note 2	122 MW
7.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Additional Capacity Transmission Service Agreement		See Note 3	73 MW
8.	IPP-Mona Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	175 MW
	IPP-Gonder Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	25 MW
9.	Nevada-Oregon Border-Sylmar	Riverside-LADWP	Bi-directional	NOB/Sylmar 25 MW Firm Transmission Service Agreement (Seasonal: June – October)		31-Oct-04	25 MW
10.	Nevada-Oregon Border-Sylmar	Riverside-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	23 MW
11.	San Onofre-Vista	Riverside-SCE	To Vista	San Onofre Nuclear Generating Station Firm Transmission Service Agmt.		See Note 5	42 MW
12.	Mead 230 kV-Vista	Riverside-SCE	To Vista	Hoover Firm Transmission Service Agreement		See Note 6	30 MW
13.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Intermountain Power Project Firm Transmission Service Agreement		See Note 7	156 MW
14.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Palo Verde Nuclear Generating Station Firm Transmission Service Agmt.		See Note 8	12 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Riverside interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Riverside interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in San Onofre Nuclear Generating Station Units 2 and 3; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Boulder Canyon Project (Hoover); or (iii) unacceptable FERC modification.
7. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Intermountain Power Project; or (iii) unacceptable FERC modification.
8. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Palo Verde Nuclear Generating Station; or (iii) unacceptable FERC modification.

TRANSMISSION CONTROL AGREEMENT

APPENDIX B

Encumbrances

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed under ISO Operational Control (per TCA Appendix A1 & A2)[1]

(Includes only those where PG&E is a service provider)

Abbreviations Used:
CDWR = California Department of Water Resources
SCE = Southern California Edison Company
SDG&E = San Diego Gas & Electric Company
SMUD = Sacramento Municipal Utility District
TANC = Transmission Agency of Northern California
WAPA = Western Area Power Administration

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
1.	Bay Area Rapid Transit	Service Agreement Nos. 42 and 43 to FERC Electric Tariff, First Revised Volume No. 12	Network Integration Transmission Service Agreement and Network Operating Agreement - OAT	10/1/2016	
2.	CDWR	Comprehensive Agreement - PG&E Rate Schedule FERC No.77	Interconnection and transmission	12/31/2014	Transmission Related Losses
3.	CDWR	Etiwanda Power Plant Generation Exchange - PG&E Rate Schedule FERC No. 169	Power exchanges	Evergreen, or on 5 years notice	
4.	CDWR	Extra High Voltage Transmission - PG&E Rate Schedule FERC No. 36	Transmission	1/1/2005	
5.	Dynegy Power Services	Control Area Transmission Agreement - PG&E Rate Schedule FERC No. 224	Transmission and various other services	Terminated 12/31/01. PG&E filing of FERC termination pending submittal of a filing to FERC.	

[1] The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
6.	DOE Laboratories, WAPA	PG&E/WAPA/DOE-SF 10/30/98 Settlement Agreement – PG&E Rate Schedule FERC No. 147	Transmission Service	3/31/2009	
7.	Lawrence Livermore National Laboratory, WAPA	PG&E/WAPA/DOE – SF Settlement Agreement - PG&E Rate Schedule FERC No. 147	Standby Transmission Service	3/31/2009	
8.	Midway-Sunset Co-Generation	Cogeneration Project Special Facilities - PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
9.	Minnesota Methane	Service Agreement No. 1, under FERC Electric Tariff, First Revised Volume No. 12	Firm Point-to-Point Transmission Service - OAT	10/1/2016	Effective 10/1/96
10.	Modesto Irrigation District	Interconnection Agreement - PG&E Rate Schedule FERC No.116	Interconnection, transmission, power sales	4/1/2008	Power sales are coordination sales - voluntary spot sales
11.	NCPA, CSC, CDWR	Castle Rock-Lakeville CoTenancy Agreement - PG&E Rate Schedule FERC No. 139	Transmission facilities maintenance	Evergreen, or 1 year notice after 1/1/2015	
12.	Path 15 Operating Instructions Settlement – Various, see FERC Docket No. ER99-1770-001	Exhibit B-1 to this Appendix B to the TCA	Implements curtailment priorities consistent with various Existing Transmission Contracts. Establishes Path 15 Facilitator role for PG&E.	3/13/2003	
13.	Power Exchange	Control Area Transmission Service Agreement - PG&E Rate Schedule FERC No. 186	Transmission and various other services	3/1/2000, or may extend if Destec does	
14.	Puget Sound Power & Light	Capacity and Energy Exchange - PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates in 2007 per 5 year advance written notice received from Puget in 2002.	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
15.	San Francisco (City and County of)	Interconnection Agreement - PG&E Rate Schedule FERC No. 114	Interconnection, transmission and supplemental power sales	7/1/2015	Power sales are Firm Partial Requirements
16.	Santa Clara (City of)	Mokelumne Settlement and Grizzly Development Agreement - PG&E Service Agreement No. 20 under FERC Electric Tariff Sixth Revised Volume No. 5	Transmission, power sales	1/1/2034	
17.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement - PG&E Rate Schedule FERC No. 38	Transmission service	7/31/2007	Both entitlement and encumbrance.
18.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan - PG&E Rate Schedule FERC No. 221	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if we are asked to cut.
19.	Shelter Cove	Interconnection Agreement- PG&E Rate Schedule FERC No. 198	Distribution	6/30/2006	Effective 8/15/96
20.	Sierra Pacific	Interconnection Agreement - PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
21.	SMUD	Interconnection Agreement - PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
22.	SMUD	EHV Transmission Agreement - PG&E Rate Schedule FERC No. 37	Transmission	1/1/2005	
23.	SMUD	Camp Far West Transmission Agreement - PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	
24.	SMUD	Slab Creek Transmission Agreement - PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
25.	(TANC) and other COTP Participants	Coordinated Operations Agreement - PG&E Rate Schedule FERC No. 146	Transmission system coordination, curtailment sharing, rights allocation, scheduling.	1/1/2043, or earlier if other agreements terminate	Establishes relationship of the COTP to the Control Area Operator.
26.	(TANC) and other COTP Participants	COTP Interconnection Rate Schedule - PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	
27.	TANC	Midway Transmission Service / South of Tesla Principles - PG&E Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation,* replacement power	Same as the COTP Interim Participation Agreement, subject to exception	
28.	Turlock Irrigation District	Interconnection Agreement - PG&E Rate Schedule FERC No. 213	Interconnection, transmission, power sales	4/1/2008, subject to exception	Power Sales are Firm Obligation Sales (Partial Requirements); Contract Firm (Firm Sale requested by TID); and Coordination Sales - Voluntary Spot Sales
29.	Vernon (City of)	Transmission Service Exchange Agreement - PG&E Rate Schedule FERC No. 148	Transmission service	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for Vernon's COTP rights
30.	WAPA	San Luis Unit - Contract No. 2207A - PG&E Rate Schedule FERC No. 79	Transmission	4/1/2016	
31.	WAPA, SCE & SDG&E	EHV Transmission Agreement - Contract No. 2947A - PG&E Rate Schedule FERC No.35	Transmission rights, exchange and coordination, and transmission service	1/1/2005, unless extended by agreement of the parties.	Both entitlement and encumbrance.
32.	WAPA	Sale, Interchange and Transmission - Contract No. 2948A - PG&E Rate Schedule FERC No. 79	Integration, interconnection, transmission and power sales and exchanges	1/1/2005	

* Includes use of PG&E's DC Intertie or PDCI for prespecified mitigation of curtailments over Path 15.

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
33.	WAPA	Wintu Pumping Plant - Contract No. 2979A - PG&E Rate Schedule FERC No. 79	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005	
34.	WAPA	Delta Pumping Plant - Contract No. DE-AC65-80WP59000 - PG&E Rate Schedule FERC No. 63	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 3 years notice	
35.	WAPA	Healdsburg, Lompoc & Ukiah - Contract No. DE-MS65-83WP59055 - PG&E Rate Schedule FERC No. 81	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 4 years notice	
36.	WAPA	Sonoma County Water Agency - Contract No. 88-SAO-40002 - PG&E Rate Schedule FERC No. 126	Transmission	6/30/94, or concurrent with Contract 2948A expiration of 1/1/2005, or 4 years notice	
37.	WAPA	New Melones - Contract No. 8-07-20-P0004 - PG&E Rate Schedule FERC No. 60	Transmission	6/1/2032	Per WAPA, commercial operation date for New Melones was 6/1/82
38.	WAPA	Trinity County PUD & Lewiston Power Plant - Contract No. 93-SAO-18008, Supplement No. 42 - PG&E Rate Schedule FERC No. 79	Transmission	1/1/2005	

Lien Mortgage

The lien of the First and Refunding Mortgage dated December 1, 1920 between PG&E and BNY Western Trust Company, as trustee, as amended and supplemented and in effect on the date hereof (the "PG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the PG&E Property which would be prior to the lien of the PG&E Mortgage; however, no consent of the trustee under the PG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

EXHIBIT B-1
(TO PG&E APPENDIX B)

Path 15 Operating Instructions
For Existing Encumbrances Across the Path 15 Interface

January 19, 1999

Introduction

As contemplated by the ISO Tariff, and as directed by the Federal Energy Regulatory Commission in its orders on Amendments 3 and 7 to the ISO Tariff, which were filed by the ISO, Pacific Gas and Electric Company (PG&E) has worked with the parties with whom it has existing contracts for transmission service over Path 15 (ETC Parties), in order to develop these Operating Instructions, which, pursuant to sections 2.4.3.1, 2.4.4.4.1, and 2.4.4.4.3 of the ISO Tariff, are to be followed by the ISO in operating this constrained Path. The constraints on Path 15 have been known by all transmission users for many years and have not been alleviated by the creation or operation of the ISO. The Operating Instructions which follow are intended to preserve each ETC Party's pre-existing contract rights to transmission service over Path 15 and PG&E's use of that transmission path. These Operating Instructions will remain in place until the earlier of (a) April 1, 2003 or (b) the expiration of the Regulatory Must-Take status of PG&E's Diablo Canyon Nuclear Power Plant. Unless otherwise mutually agreed by all parties, these Operating Instructions will be in effect for this interim period, only, and all parties reserve all rights to argue for the implementation of different Operating Instructions and priorities for Path 15 consistent with their ETC contract rights, following this interim period. Further, any party may oppose any modification of these Operating Instructions that materially affects the rights of such party as set forth herein.

Purpose and Objectives

These Path 15 Operating Instructions provide direction to the ISO regarding the management of congestion on Path 15 during the ISO's Day Ahead, Hour Ahead and Real Time markets. The objective of these instructions is to assure, on an ongoing basis, the efficient use each day of available Path 15 transfer capability while maintaining the transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date. These instructions also clarify individual and joint responsibilities between the ISO as the Control Area Operator and PG&E as the Path 15 Existing Transmission Contract (ETC) Facilitator.[1/]

1/ Specific operating instructions have been provided to the ISO by PG&E in other documents for each of the Existing Contracts for which it is the Responsible Participating Transmission Owner on Path 15. In the contract specific instructions, information is provided on the maximum MW of transmission service available over the path; the quality of transmission service; daily, hourly and real time scheduling rights and responsibilities; curtailment procedures; points of receipt and points of delivery and effective and termination dates of the contract. This set of additional instructions will clarify how the relative

These instructions are to be adhered to except when the ISO determines that system reliability requires that other steps be taken. The ISO is solely responsible for continued system reliability and must unilaterally take all steps necessary to preserve the system in times of emergency.

Path 15 Existing Transmission Contract Facilitator (ETC Facilitator)

PG&E will serve in the capacity of ETC Facilitator to assist the ISO and to provide necessary guidance to the ISO in the administration of Path 15 ETC rights. The ETC Facilitator shall:

1. Provide to the ISO for each hour of the Trading Day, the total amount of megawatts that should be reserved for use by the ETC Parties.[2/] Such amounts shall be provided generally by 8:30 a.m. of each weekday prior to the start of a Trading Day for the Day-Ahead Market, and generally by 4:30 p.m. of the weekday prior to the start of a Trading Day for the Hour-Ahead Market.[3]

2. Facilitate all Path 15 schedules from ETC Parties, including those ETC Parties for which the ETC Facilitator is not the Scheduling Coordinator (SC).

3. Schedule all SC to SC transfers[4/] that utilize ETC rights across Path 15.

4. Inform ETC Parties, affected SCs, and the ISO, pursuant to these Operating Instructions, when an ETC Party's scheduled usage of Path 15 is reduced and the amount of such reduction.

5. In performing these tasks, ensure that all transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date are maintained and protected.

---

transmission rights and priorities of the parties should be managed and administered during times of congestion and possible curtailment on Path 15.

[2/] The ETC Facilitator's specification of the megawatt reservation amount does not limit, in any way, ETC Parties' ability to exercise their rights, including making schedule changes in real time.

[3/] PG&E and most of the ETC Parties pre-schedule Monday through Friday only. PG&E generally provides its ETC reservation for Sunday and Monday by close-of-business on Friday and to the extent practicable, encourages ETC Parties to provide pre-schedules in time to meet the ISO's Day-Ahead market deadline.

[4/] Currently, Southern California Edison Company (Edison) schedules its SC-SC transfers for its Existing Contracts directly with the ISO. Upon mutual agreement by Edison and PG&E, PG&E may become a party to these SC-SC transfers across Path 15.

Day-Ahead Market Congestion Management

Prior to the start of the ISO Day-Ahead process, the ETC Facilitator will provide the ISO with an hourly reservation for ETC schedules utilizing Path 15. The ISO will determine the hourly amount of the Path 15 operating limit available for New Firm Uses[5/] for use in its Congestion Management Process[6/] by subtracting the ETC megawatt reservation amount from the operating limit for Path 15 for each hour. After the deadline for receiving Day-Ahead Preferred Schedules, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for each hour of congestion on Path 15. ETC schedules over Path 15 will not be assessed Usage Charges.

Hour-Ahead Market Congestion Management

Because scheduling timelines in ETC Parties' contracts (including third party contracts using ETC Party rights) differ from the ISO's scheduling timeline, some pre-schedules from such parties are likely to be scheduled in the Hour-Ahead Market. The ETC Facilitator's ETC megawatt reservation amount submitted in the Day-Ahead Market is intended to provide sufficient reservation to accommodate the schedules submitted in the Hour-Ahead Market. After the close of the Hour-Ahead Preferred Market, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for such hour on Path 15. ETC schedules over Path 15 will not be assessed Usage Charges.

Real Time Curtailment Priorities

Any and all ETC Parties' rights (including third party contracts using ETC Party rights) to change schedules after the close of the ISO's Hour-Ahead market will continue to be honored. In the event of curtailments on Path 15 South-to-North in real time, the ETC Facilitator will determine the appropriate order and magnitude of curtailments given the circumstances that occur in real time and the terms and provisions of the ETCs. This determination will be made consistent with the following table "Path 15 South-to-North Real-Time Curtailment Priorities", a copy of which is Attachment A, which is incorporated into and made a part of these Path 15 Operating Instructions by this reference.

In Attachment A, the relative priorities of the various ETC Parties' transmission service rights across Path 15 in real-time are identified by grouping the various rights into

---

[5/] Regulatory Must Take and Regulatory Must Run resources that contribute to the "imputed use" of Path 15 are treated as New Firm Uses for this purpose. The "imputed use" is the expected power flow resulting from the load, interchange, and resource schedules of all SCs.

[6/] The ISO's Congestion Management Process uses Adjustment Bids to reduce the amount of New Firm Use, if necessary, so that such use does not exceed the amount of the Path 15 operating limit less the ETC reservation megawatt amount.

separate blocks and ordering the blocks by their relative priority. Attachment A addresses only Path 15 South to North real-time curtailment priorities. The Path 15 North-to-South real-time curtailment priorities will be addressed in a separate and distinct set of Operating Instructions and will be separately submitted to the ISO after review by the Path 15 ETC Parties.

EXHIBIT B-1
(TO PG&E APPENDIX B)

ATTACHMENT A

Path 15 Real-Time South-to-North Curtailment Priorities [1/]

Priority Group	ETC/Priority Holder	South-to-North
1 [2/]	CDWR EHV Agreement [3/] SCE CCPIA encumbered rights [4/] SDG&E CCPIA encumbered rights [5/] PG&E must-take encumbrances CDWR Comprehensive Agreement	300 MW up to 667 MW 0 [6/] 810 MW
2	TANC SOTP [7/]	300 MW
3 [8/]	SMUD TRS (Reserve rights) TID IA (Reserve rights)	400 MW 32 MW
4	Other Encumbrances	189.5 MW [9/]
5 [10/]	PG&E SOTP SCE CCPIA unencumbered rights ' SDG&E CCPIA unencumbered rights '	500 MW varies monthly 109 MW
6	New ETC Requests [11/] Other "As Available"	unspecified

1/ This table may change from time to time as existing contracts are terminated, or the rights under those contracts change (e.g., termination of a QF contract).

2/ Curtailments within Priority Group 1 are pro rata based on each party's contract right or entitlement amount.

3/ CDWR has both EHV and Comprehensive Agreement rights. When curtailments are required, CDWR's EHV schedules are curtailed beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).

4/ Some of SCE's CCPIA rights have been or may be converted for ISO use. When curtailments are required, schedules using these rights are curtailed in accordance with previously established monthly maximum usage levels as agreed upon by SCE and PG&E.

5/ All of SDG&E's CCPIA rights have been converted for ISO use.

6/ The Priority Group 1 capacity available to PG&E south-to-north in real time is the capacity remaining after CDWR's EHV and SCE/SDG&E's CCPIA Existing Contract schedules (as may be curtailed) are subtracted from the amount of available capacity. This remaining capacity is available for CDWR's Comprehensive Agreement schedules and PG&E's must-take encumbrances. PG&E's must-take encumbrances rights correspond to the amount of Path 15 south-to-north transfer capability historically available for PG&E must-take generation in SP 15, including but not limited to the generation of PG&E's Diablo Canyon Nuclear Power Plant, minus PG&E load in SP15. As used in this footnote, "PG&E's must-take encumbrances" means an amount of transmission transfer capability that is reserved for ISO New Firm Uses across Path 15 south-to-north that is the lesser of PG&E's must-take encumbrances rights defined above and the PX imputed use of Path 15. The PX imputed use of Path

15 is the expected power flow resulting from the load, interchange and resource schedules of the PX across Path 15. CDWR's Comprehensive Agreement schedules are curtailed, pro rata with the Priority Group 1 capacity available to PG&E, beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).

7/ TANC's 300 MW is firm bi-directional service using the Points of Receipt and Delivery set forth in section 2.4 of the SOTP and in accordance with the Curtailment Priorities set forth in section 3.2 of the SOTP. PG&E supports these transfer capabilities by implementing mitigation measures when necessary, to the extent such measures are available, up to a total of 200 MW south-to-north and 700 MW north-to-south. These mitigation measures consist of switching PG&E's scheduled transmission service from the AC Lines to the DC Line.

8/ Curtailments within Priority Group 3 are pro rata based on the MW amount of each party's rights.

9/ Priority Group 4 status is available, south-to-north, for only 189.5 MW. Any increases in south-to-north rights under ETCs in Priority Group 4 are designated as "New ETC Requests" and will have Priority Group 6 status.

10/ Priority Group 5 is available for ISO use for New Firm Uses.

11/ "New ETC Requests" includes any requested service by an ETC in excess of the rights set forth in this table for Priority Groups 1-5, provided that this footnote shall not apply to arrangements between or among PG&E and one or more ETC Parties for future capacity upgrades, if such parties agree, or an existing contractual commitment provides otherwise.

TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
1.	Devers - Mirage / Coachella 230 kV	IID	SCE to IID	Firm Transmission Service Agreement	268	On 3-year notice	100 MW May-October, 50 MW rest of the year.
2.	Devers - Banning ISO Grid Take Out Point serving Banning	Banning	Bi-dir	Pasadena Firm Transmission Service	382	Earlier of 12/31/03 or upon Banning's 1-year notice given after 1/1/02.	10 MW until 10/31/98, 5 MW beginning 1/1/99
3.	Devers - ISO Grid Take Out Point serving Banning	Banning	To Banning	1995 San Juan Unit 3 Firm Transmission Service Agreement	381	Earlier of termination of Banning's interest in San Juan Unit 3 or Banning's 1-year notice given after 1/1/03	15 MW
4.	Devers-- Vista	Colton	To Vista	1995 San Juan Unit 3 Firm Transmission Service Agreement	265	Earlier of termination of Colton's interest in San Juan Unit 3 or Colton's 1-year notice given after 1/1/03	14.043 MW
5.	Hinds - Vincent	MWD	Bi-dir.	District-Edison 1987 Service and Interchange Agreement	203	9/30/2017 or five-year notice	110 MW
6.	Etiwanda - Vincent	MWD	to Vincent	Amended and Restated District Etiwanda Power Plant Transmission Service Agreement	292 First Revised	Earliest of termination MWD-PG&E Sale Contract, termination of PG&E-CDWR Exchange Contract, termination of SCE-CDWR Power Contract, termination of Interconnection Facilities Agreement, or April 1, 2014. As of the date of this document, this agreement is expected to terminate 12/31/04, which is the date the CDWR Power Contract is expected to terminate.	24 MW

Footnotes:

1. The following is an additional encumbrance that does not fit into the format for existing contract encumbrances. The additional encumbrance is: The lien of the Trust Indenture dated as of October 1, 1923, between Edison and Harris Trust and Savings Bank and Pacific-Southwest Trust & Savings Bank (D. G. Donovan, successor trustee), as trustees ("the Edison Indenture"). The transfer of control to the ISO pursuant to this Agreement (i) does not require any consent from the trustees under the Edison Indenture, (ii) shall not be deemed to create any lien or charge on the Edison Transmission Assets that would be prior to the lien of the Edison Indenture, and (iii) shall not otherwise impair the lien of the Edison Indenture.
2. The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
7.	Eldorado-Vincent	CDWR	Bi-dir.	Amended and Restated Firm Transmission Service Agreement (Eldorado-Vincent)	113 First Revised	Earlier of date that a) CDWR has obtained for replacement transmission service; b) CDWR is no longer entitled to Reid Gardner Unit 4 output; c) 12/31/2020; or, d) Reid Gardner Unit 4 is permanently retired from service.	235 MW
8.	Eldorado / Mohave - Lugo	LADWP	Bi-dir.	Victorville - Lugo Interconnection Agreement	51	2019 or sooner by mutual agreement	Edison is required to provide capacity to LADWP equal to the product of LA's Capacity Share and the deemed capacity of the transmission system consisting of Mohave-Lugo, Mohave-Eldorado, Eldorado-Lugo, Eldorado-McCullough, McCullough-Victorville lines, and Victorville-Lugo 500 kV transmission lines.
9.	Moenkopi - Eldorado	USA, APS, SRP, NPC, LADWP, TGE	Bi-dir.	Edison - Navajo Transmission Agreement	264	5/21/23	In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency service transmission rights without a charge.
10.	Mohave - Eldorado	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Mohave-Eldorado line is curtailed, *pro-rata* back up is provided on Mohave-Lugo and Eldorado-Lugo lines. If Mohave-Lugo is curtailed, *pro-rata back-up is provided* on Mohave-Eldorado. Amount of back up capacity is up to participant's Mohave Capacity Entitlement. For curtailment purposes, Capacity Entitlements are: Edison-884 MW; LADWP-316 MW; NPC-222 MW;SRP-158 MW.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
11.	Eldorado - Mead	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425	7/1/06	If Eldorado-Mead lines are curtailed, line capacity is allocated pro rata in proportion to the following Capacity Entitlements: NPC-222 MW; SRP-158 MW; LADWP – 0 MW; Edison Capacity Entitlement is equal to entire capacity of the Eldorado-Mead Line Nos. 1&2 minus NPC Capacity Entitlement minus SRP Capacity Entitlement.
12.	Mead - Mohave	NPC	To Mohave	Amended and Restated Agreement for Additional NPC Connection to Mohave Project	426	Co-terminous with Mohave Project Plant Site Conveyance and Co-Tenancy Agreement	Up to 222 MW of Back-up transmission service.
13.	Mead - ISO Grid Take Out Point serving Banning	Banning	E-W	Hoover Firm Transmission Service Agreement	378	Earliest of: agreement to terminate, or date in a Banning 1-year notice given after 1/1/02, or termination of WAPA Service Contract	2 MW
14.	Mead - Rio Hondo	Azusa	E-W	Sylmar Firm Transmission Service Agreement	375	Earliest of: agreement to terminate, or Azusa's 1-year notice given after 1/1/02, or termination of Azusa's interest in San Juan #3	8 MW
15.	Mead - Rio Hondo	Azusa	E-W	Hoover Firm Transmission Service Agreement	372	Earliest of: agreement to terminate, or date in an Azusa 1-year notice given after 1/1/02, or termination of WAPA Service Contract	4 MW
16.	Mead - Vista	Colton	E-W	Hoover Firm Transmission Service Agreement	361	Earliest of: agreement to terminate, or date in a Colton 1-year notice given after 1/1/02, or termination of WAPA Service Contract	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
17.	Mead - Riverside	Riverside	E-W	Hoover Firm Transmission Service Agreement	389	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.	30 MW
18.	Mead - Laguna Bell	Vernon	Bi-dir	Mead Firm Transmission Service Agreement	207	Earlier of agreement to terminate or termination of Hoover Power Sales Agreement	26 MW
19.	Mead - Mountain Center	AEPCO	E-W	Firm Transmission Service Agreement	131	7/1/21 or on 10 years notice	10 MW
20.	Palo Verde - Devers	LADWP	Bi-dir	Exchange Agreement	219	Earliest of construction of DPV#2, or removal of DPV1 from service, or transfer of DPV#2 rights of way to LADWP.	368 MW
21.	Palo Verde - Sylmar	LADWP	Bi-dir.	Exchange Agreement	219	5/31/2012	100 MW
22.	Sylmar - Devers	LADWP	Bi-dir	Exchange Agreement	219	When DPV#1 is removed from service, or if DPV#2 is built, the date DPV#2 is removed from service	368 MW
23.	Palo Verde - Devers Devers - Valley Valley - Serrano Serrano - SONGS	IID, APS, SDG&E	Bi-Dir.	Mutual Assistance Transmission Agreement	174	On 2034 or sooner by agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in an operating bulletin.
24.	Midway - Vincent 500 kV	PG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	633 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
25.	Midway - SONGS	SDG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	161 MW
26.	Midway - Vincent 500 kV	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25	320 MW
27.	Midway - Vincent 500 kV	CDWR	Bi-dir.	Amended and Restated Power Contract	112 First Revised	12/31/04	235 MW
28.	Midway - Vincent 500 kV	PG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	655 MW
29.	Midway - SONGS	SDG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20- SDG&E)	7/31/07	109 MW
30.	Midway - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement, or 12/29/42 (50 yrs).	60 MW until 1/1/00, 60MW after 12/31/07
31.	COB - Tesla 500 kV	SMUD	Bi-dir.	Contract between California Companies and Sacramento Municipal Utility District for Extra High Voltage Transmission and Exchange Service	39	Useful life of existing Pacific Intertie per Amendment #2	200 MW
32.	Pacific AC 500 kV Intertie	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25	320 MW
33.	COB-Sylmar - Rio Hondo	Azusa	To Sylmar and Rio Hondo	Pacific Intertie Firm Transmission Service	377	Earlier of 10/31/03, or upon Azusa's 1-year notice given after 1/1/02	28 MW May-October of 1998, 15 MW May-October thereafter
34.	COB - Sylmar	Banning	To Sylmar	Pacific Intertie Firm Transmission Service	383.1	Earlier of 10/31/03, or upon Banning's 1-year notice given after 1/1/02	10 MW May-October of 1998, 5 MW May-October thereafter
35.	COB - Sylmar-Vista	Colton	To Sylmar and Vista	Pacific Intertie Firm Transmission Service	366	Earlier of 10/31/03, or upon Colton's 1-year notice given after 1/1/02	15 MW May-October

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
36.	SONGS - Vista	Riverside	To Vista	SONGS 2 & 3 Firm Transmission Service Agreement	393	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.	42 MW (per 1997 Edison – Riverside Restructuring Agreement)..
37.	Victorville/Lugo - Midway	MSR	Bi-Dir.	Amended and Restated Firm Transmission Service Agreement (Victorville/Lugo-Midway)	339 First Revised	Earlier of: five-year notice by MSR, or life of Mead-Adelanto 500 kV Transmission Project	150 MW
38.	Victorville/Lugo - Vista	Riverside	To Vista	Intermountain Power Project Firm Transmission Service Agreement	391	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.	156 MW (per 1997 Edison – Riverside Restructuring Agreement).
39.	Victorville/Lugo - Rio Hondo	Azusa	To Rio Hondo	PVNGS Firm Transmission Service Agreement	373	Earliest of: termination agreement, Azusa's 1-year notice given after 1/1/02, termination of PVNGS entitlement, or termination of PVNGS participation.	4 MW
40.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	To Banning	PVNGS Firm Transmission Service Agreement	379	Earliest of: agreement to terminate, or Banning's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
41.	Victorville/Lugo - Vista	Colton	To Vista	PVNGS Firm Transmission Service Agreement	362	Earliest of: agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
42.	Victorville/Lugo - Vista	Riverside	To Vista	PVNGS Firm Transmission Service Agreement	392	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.	12 MW (per 1997 Edison – Riverside Restructuring Agreement).
43.	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360	Terminates with permanent removal of Mead-Adelanto from service	11 MW
44.	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360	Up to term of agreement	64 MW
45.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	Bi-dir.	Sylmar Firm Transmission Service Agreement	380	Earliest of agreement to terminate, or Banning's 1-year notice given after 1/1/02, or termination of Bannings interest in San Juan #3.	5 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
46.	Victorville/Lugo - Rio Hondo	Azusa	to Rio Hondo	Pasadena FTS	374	Earliest of agreement to terminate, or Azusa's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	14 MW
47.	Victorville/Lugo - Vista	Colton	to Vista	Pasadena FTS	363	Earliest of agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	18 MW
48.	Sylmar - Rio Hondo	Azusa	To Rio Hondo	1995 San Juan Unit 3 FTS Agreement	376	Earlier of: termination of Azusa's interest in San Juan Unit #3 or Azusa's 1-year notice given after 1/1/02	Sum of 10 MW continuous plus 15 MW (May through October 1999 through 2003) (Per 1997 Edison – Azusa Restructuring Agreement)

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
49.	Sylmar - Goodrich	Pasadena	Sylmar-Goodrich	Pasadena-Edison 230-kV Interconnection and Transmission Agreement	55	8/4/10	200 MW; Edison also responsible for delivery of up to 15 MW of Azusa Hydro Energy to Pasadena at Goodrich
50.	Sylmar - Vista	Colton	Bi-dir.	Sylmar Firm Transmission Service Agreement	364	Earliest of: agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of Idaho service contract.	3 MW
51.	Sylmar - Midway	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: termination of PG&E Transmission Agreement, or 12/29/42 (50 yrs).	93 MW until 1/1/00, 93MW after 12/31/07
52.	Sylmar - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement or 12/29/42 (50 yrs).	93 MW until 12/31/02, 60 MW after 12/31/02
53.	Sylmar - SONGS	SDG&E	To SDG&E	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	100 MW
54.	Sylmar - SONGS	SDG&E	To Sylmar	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	105 MW
55.	Sylmar - Vincent	CDWR	Bi-dir.	Amended and Restated Power Contract	112 First Revised	12/31/04	120 MW
56.	Sylmar - Mead	PG&E	To Mead.	Amended and Restated Edison-PG&E Transmission Agreement	256 First Revised	7/31/07	Up to 200 MW of FTS.
57.	Point of Delivery: COB or NOB	BPA	S-N	Long Term Power Sales & Exchange Agreement	222	Per five year notice from BPA dated 10/29/1999, contract will terminate early on 11/1/2004	Up to 850 MW under the exchange modes.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
58.	Point of Delivery: Midway or 500 kV bus at Vincent	CDWR	S-N	Amended and Restated Capacity Exchange Agreement	148 First Revised	12/31/2004	Depending on time and day: Minimum=225 MW Maximum=1550 MW for both the Power Contract and Capacity Exchange Agreement
59.	Point of Delivery: Midway or 500 kV bus at Vincent	CDWR	S-N	Amended and Restated Power Contract	112 First Revised	12/31/2004	Included under Capacity Exchange Agreement Contract Amount Column
60.	Point of Delivery: Palo Verde, Four Corners, Moenkopi	Tucson	W-E	Amended and Restated Tucson Power Exchange Agreement	271 First Revised	5/14/2005	110 MW
61.	Hoover - Mead	WAPA	Bi-dir.	Lease of Two 230-kV Transmission Lines Between Hoover Power Plant and Mead Substation	304	9/30/2017 or upon 3-years' notice by WAPA; WAPA entitled to renew through life of Hoover.	Entire capacity leased to WAPA.
62.	Calectric - Vincent	CDWR	To Vincent	Amended and Restated CDWR Devil Canyon Power Plant Additional Facilities and Firm Transmission Service Agreement	421	Life of Plant	120 MW
63.	Mojave Siphon - Vincent	CDWR	To Vincent	CDWR Mojave Siphon Additional Facilities and Firm Transmission Service Agreement	342	Life of Plant	28 MW
64.	Vincent - Oso	CDWR	to Oso	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	72 MW
65.	Vincent - Pastoria	CDWR	to Pastoria	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	787 MW
66.	Warne - Vincent	CDWR	To Vincent	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	82 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
67.	Vincent - Pearblossom	CDWR	To Pearblossom	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	152 MW
68.	Blythe - Cibola, & Ehrenberg (Buckskin service does not go through ISO system)	APS	To APS Load	Amended and Restated Firm Transmission Service (Blythe Accounts)	348 First Revised	Upon 3-year notice by APS, or 10 year notice by Edison	Presently 4.2 MW, 7 MW max.
69.	Malin – Round Mountain - Tracy	USBR (WAPA), California Companies	Bi-directional	USBR Contract with California Companies for Extra High Voltage Transmission And Exchange Service	37	1/1/2005	400 MW
70.	COB – Midway	State of CA. (CDWR), California Companies	Bi-directional	Contract between State of California and California Companies for the Sale, Interchange, and Extra High Voltage Transmission of Electrical Capacity and Energy	38	1/1/2005	300 MW

SDG&E APPENDIX B

SDG&E'S ENCUMBRANCES

I. Local Furnishing Transmission System Encumbrances

The ISO shall exercise Operational Control over SDG&E's Local Furnishing Transmission System consistent with the following Encumbrances in accordance with the Local Furnishing Debt Operating Procedures that SDG&E has provided the ISO:

A. Section 9600(a)(6) of the California Public Utilities Code provides that Participating TOs shall not be compelled to violate restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995.

SDG&E's transmission facilities and other electric properties are financed in part with the proceeds of Local Furnishing Bonds. Prior to December 20, 1995, pursuant to provisions of the loan agreement, engineering certificates, and tax certificates and agreements associated with outstanding Local Furnishing Bonds issued for its benefit, SDG&E has convenanted not to take or permit any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit. Accordingly, notwithstanding anything to the contrary contained in the Agreement, including SDG&E's agreement to be bound by the terms of the Restated and Amended ISO Tariff and the Restated and Amended TO Tariff, SDG&E may not take (nor may SDG&E allow the ISO to take) any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, including (without limitation) the actions specified below.

B. Absent an approving written opinion of nationally recognized bond counsel selected by SDG&E, SDG&E will not operate its facilities (or allow its facilities to be operated) so as to cause or permit a cumulative annual net outbound flow of electric energy from the points of interconnection between (i) SDG&E's wholly-owned transmission lines which are directly connected to SDG&E's electric distribution facilities in San Diego and Orange Counties, and (ii) other electric properties. As of January 1, 1998, these interconnection points include:

1. the point at the International Border where SDG&E's ownership interest in the 230 kV Miguel/Tijuana transmission line interconnects with Comision Federal de Electridad's ownership interest in the Miguel/Tijuana transmission line;

2. the set of points at the San Onofre Nuclear Generating Station ("SONGS") where SDG&E's wholly-owned transmission facilities interconnect with a switchyard but which is owned (in whole or in part) by Southern California Edison Company ("SCE");

3. the point where SDG&E's wholly-owned segment of the 500 kV Miguel/Imperial Valley transmission line interconnects with the Imperial Valley Substation;

4. the point at the San Diego/Imperial Valley border where SDG&E's ownership interest in a 2.5 mile-long radial distribution line interconnects with Imperial Irrigation District's ownership interest in that same distribution line;

5. the point at the Riverside/Orange County border and the Riverside/San Diego County border where SDG&E's ownership interest in several isolated distribution lines interconnect with SCE's ownership interest in those same distribution lines;

6. the point where SDG&E's wholly-owned Narrows Substation intereconnects with transmission facilities which are owned by Imperial Irrigation District.

C. For purposes of paragraph B, net flows shall be calculated by treating as an outbound flow at the SONGS switchyard bus all electric energy generated at SONGS on behalf of SDG&E (i.e., consequent to SDG&E's interest in SONGS) that is not transmitted into SDG&E's electric service area in San Diego and Orange Counties. Electric energy generated at SONGS on behalf of SDG&E that is transmitted into SDG&E's service area, whether for delivery to retail customers of SDG&E or for other uses, shall not be treated as an inbound flow at the SONGS switchyard bus interconnection for purposes of this calculation.

D. SDG&E will not operate its facilities (or allow its facilities to be operated) so as to curtail delivery of electric energy to its native load customers involuntarily in order to provide electric energy to customers outside of its electric service territory in San Diego and

Orange Counties, unless such curtailment is necessitated by the failure of facilities either partially or wholly owned by SDG&E.

E. Upon SDG&E's receipt of a written request by the ISO to take (or to refrain from taking) any action that SDG&E believes might jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, SDG&E in good faith shall promptly seek to obtain an opinion (of the type generally regarded in the municipal bond market as unqualified) from a nationally recognized bond counsel selected by SDG&E that the requested action (or inaction) will not adversely affect such tax-exempt status. Until the opinion of bond counsel described above is obtained, SDG&E shall not be required to take (or to refrain from taking) the specified action, and the ISO shall exercise its Operation Control consistent with such limitation.

F. If the ISO proposes to set rates for transmission over SDG&E's transmission facilities based in whole or in part upon the costs to Participating Transmission Owners other than SDG&E (see, e.g., California Public Utilities Code § 9600(a)(2)), the ISO will return Operating Control over SDG&E's transmission facilities to SDG&E unless SDG&E, in good faith, has obtained an opinion (of the type generally regarded in the municipal bond market as unqualified) from nationally recognized bond counsel selected by SDG&E that the proposed ratemaking will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E.

G. If SDG&E has been unable to obtain the unqualified opinion of bond counsel described in sections E and F above, upon written request by a entity eligible to file an application under Section 211 of the Federal Power Act ("FPA")(or the ISO acting as its agent)(collectively, the "Eligible Entity"), SDG&E in good faith shall promptly seek to obtain a ruling from the Internal Revenue Service that the requested action (or inaction) or transmission rates will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E. If such a ruling cannot be obtained, SDG&E will not object to an Eligible Entity seeking an order under Section 211 of the FPA with respect to the requested action (or inaction) or transmission rates.

II. Mortgage Lien

The ISO shall acknowledge the mortgage lien set forth below:

A. The lien of the Mortgage and Deed of Trust dated July 1, 1940 between San Diego Gas & Electric Company and The Bank of California, as trustee, as amended and supplemented and in effect on the date hereof (the "SDG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the property subject to the SDG&E Mortgage which would be prior to the lien of the SDG&E Mortgage; however, no consent of the trustee under the SDG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

APPENDIX B.2

SDG&E's List of Contract Encumbrances[1]/[2]

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey Tap - Mission - Talega (2 lines) - Encina
79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy without charge.

[1] An additional encumbrance pertaining to Local Furnishing Bonds that does not fit into the format for existing contract encumbrances is set forth at pages SDG&E App. B-1 through B-3 hereof.

[2] An additional encumbrance pertaining to SDG&E's lien of Mortgage and Deed of Trust that does not fit into the format for existing contract encumbrances is set forth at page SDG&E App. B-4 hereof.

78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031	In the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E Transmission System Participation Agreement	IID		June 24, 2051	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E – 85.64%; and IID – 14.36%.
78-003	APS-SDG&E Transmission System Participation Agreement	APS		July 31, 2031	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS – 11%; SDG&E - 69%; IID - 20%.
QFD000.016	Power Sale Agreement between SDG&E-City of Escondido for the Rincon Indian Reservation	City of Escondido	76	Agreement to be terminated effective upon FERC acceptance of Notice of Termination.	Obligates SDG&E to sell and deliver electricity at stated prices to the City of Escondido for resale to the United States Indian Services at the Rincon Indian Reservation.

1/ TANC's 300 MW is firm bi-directional service using the Points of Receipt and Delivery set forth in section 2.4 of the SOTP and in accordance with the Curtailment Priorities set forth in section 3.2 of the SOTP. PG&E supports these transfer capabilities by implementing mitigation measures when necessary, to the extent such measures are available, up to a total of 200 MW south-to-north and 700 MW north-to-south. These mitigation measures consist of switching PG&E's scheduled transmission service from the AC Lines to the DC Line.

APPENDIX B: CITY OF VERNON'S

ENCUMBRANCES

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC NO.	CONTRACT TERMINATION	CONTRACT AMOUNT
1. COTP [1]	Vernon, PG&E		Transmission Service Exchange Agreement Between Pacific Gas & Electric Company and the City of Vernon	148	See Notes (1) – (3)	121 MW N-S 92 MW S-N
2.	PG&E, SCE, SDG&E, and COTP Participants		Coordinated Operation Agreement	146	Earlier of: 1/1/2043, agreement governing the interconnection of the COTP with PG&E is no longer in force, or any of the binding agreements terminate.	

Contract Termination:

(1) This Agreement may be terminated on July 31, 2007:

A. By PG&E with one year notice to Vernon if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in DC Line at NOB.
B. By Vernon if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.
C. If the DC Line or COTP facilities are retired.

(2) In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

(3) Otherwise, the Agreement remains in effect for fifty years from the effective date.

[1] PG&E is an existing PTO and a joint-owner of COTP. We believe documents relating to the COTP are submitted to the CAISO by PG&E.

Vernon has only minority ownership interests in the high voltage transmission facilities presently placed under the ISO's Operational Control by Vernon, which consist of Vernon's minority interests in COTP, MPP, MAP, and the Marketplace Substation/Expansion of and/or interconnection to these facilities require approval of the owners and/or the management committees of those facilities. Therefore, as the Commission determined in approving Vernon's TO Tariff in Docket No. EL00-105, 96 FERC ¶ 61,312 (September 14, 2001), Vernon does not have the legal authority to compel expansion of and/or interconnection to those facilities. Such encumbrances pertaining to Vernon's minority interests in the facilities turned over to ISO operational control that do not fit into the format of the table above are listed below:

Mead-Phoenix Project

1. Mead-Phoenix Project Joint Ownership Agreement and Definitions
2. Mead-Phoenix Project Fiscal Agency Agreement
3. Mead-Phoenix Project Construction Management Agreement
4. Mead-Phoenix Project Land Rights Agreement
5. Mead-Phoenix Project Operation Agreement
6. Mead-Phoenix Project, Mead-Westwing Transmission Line, Westwing Substation Interconnection Agreement (DWP No. 10408)
7. Mead-Phoenix Project, Mead Interconnection Agreement

Mead-Adelanto Project

8. Marketplace Substation Participation Agreement (DWP No. 10330)
9. Mead-Phoenix/Mead-Adelanto Projects, Marketplace-McCullough 500 kV Interconnection Agreement (DWP No. 10409)
10. Mead-Adelanto Project Joint Ownership Agreement and Definitions
11. Mead-Adelanto Project Fiscal Agency Agreement
12. Mead-Adelanto Project Construction Management Agreement (DWP No. 10335)
13. Mead-Adelanto Project Operation Agreement (DWP No. 10336)
14. Mead-Adelanto Project, Marketplace-Adelanto Transmission Line, Adelanto Switching Station Interconnection Agreement (DWP No. 10338)
15. Marketplace Static Var Compensator, Adelanto Switching Station Interconnection Agreement (DWP No. 10332)

California-Oregon Transmission Project

1. Interim Participation Agreement
2. Project Operation and Maintenance Agreement
3. COTP-Western Interconnection Agreement
4. Pacific Northwest Interim Interconnection Agreement
5. Memorandum of Understanding

APPENDIX B: CITY OF ANAHEIM ENCUMBRANCES

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1	Mona Substation-Gonder Substation	Anaheim-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		7-Jun-94	31-Dec-09	20 MW

APPENDIX B: CITY OF AZUSA
ENCUMBRANCES

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1. ANPP (Devers) - Sylmar	Azusa, Los Angeles		Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021		10 MW

Los Angeles – Azusa ANNP/Sylmar FTS:
Pursuant to Section 6.2 of the Los Angeles – Azusa ANNP/Sylmar FTS, the Los Angeles Department of Water and Power is entitled to schedule energy on a nonfirm basis over the 10 MW of bidirectional transmission service between Palo Verde and Sylmar to the extent Azusa does not use the transmission service.

Summary- details are in each agreement.

APPENDIX B: CITY OF RIVERSIDE ENCUMBRANCES

Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1. Mona Substation-Gonder Substation	Riverside-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		17-Jun-94	31-Dec-09	20 MW

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO MAINTENANCE STANDARDS

1. DEFINITIONS[1]

Availability - A measure of time a Transmission Facility under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures - The frequency and accumulated duration of Forced Outages$^{(IMS)}$ for each of the Transmission Line Circuits within a Voltage Class for a given calendar year.

Availability Measure Targets- The Availability performance goals established by the ISO.

Forced Outage$^{(IMS)}$ - A Forced Outage$^{(IMS)}$ occurs when a Transmission Facility is in an Outage$^{(IMS)}$ condition regardless of duration and: (1) there is no Scheduled Outage request in effect with respect to that period; or (2) the Transmission Facility is in an Outage$^{(IMS)}$ condition for a period that exceeds the period specified in the Scheduled Outage request, in which case a Forced Outage$^{(IMS)}$ is deemed to exist for the balance of the period, unless the PTO requests and is granted an extension to the approved Scheduled Outage request.

ISO Maintenance Guidelines - Criteria presented herein which are to be followed by each PTO in preparing its PTO Maintenance Practices.

[1] A term followed by the supercript "(IMS)" denotes a term which has a special, unique definition in this Appendix.

ISO Maintenance Standards - Those maintenance standards which result from the combination of each PTO's Maintenance Practices and their respective Availability Measures .

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities.

Maintenance Coordination Committee - A committee responsible for recommending to the ISO modifications to and implementation of the ISO Maintenance Standards. The committee shall be organized and operate in accordance with Section 7.0 of this document.

Outage$^{(IMS)}$ - Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO - A Participating Transmission Owner as defined in Appendix D of the Transmission Control Agreement.

PTO Maintenance Practices - A description of methods used by a PTO for the Maintenance of each substantial type of Transmission Facility or component in its system which is under the Operational Control of the ISO. The PTO Maintenance Practices are to be prepared in accordance with the ISO Maintenance Guidelines.

Scheduled Outage - The removal from service of a Transmission Facility under ISO Operational Control to perform work on specific components in accordance with the requirements of the Transmission Control Agreement.

Section 348 Criteria - The criteria for maintenance standards established by Section 348 of the California Public Utilities Code, as in effect from time to time, to "provide for high quality, safe and reliable service", taking into consideration "cost, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience".

Stations - Facilities under the Operational Control of the ISO for purposes such as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and system protection equipment.

Transmission Line Circuit - The continuous set of transmission conductors located primarily outside of a Station, and apparatus terminating at interrupting devices which would be isolated from the transmission system following a fault on such equipment.

Voltage Class - The voltage to which operating, performance, and maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

2. INTRODUCTION

These standards were prepared by the ISO through a lengthy consensus building effort involving a diverse group of stakeholders (i.e., the ISO Maintenance Standards task force).

2.1. Objective

The Maintenance of Transmission Facilities has several objectives:

- Ensuring that the safety and Availability performance levels inherent to the Transmission Facilities are achieved,
- Restoring the safety and Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Gathering information that can be of use as the basis for identifying improvements to those Transmission Facilities whose Availability performance is inadequate,
- Gathering information that can be used as the basis for optimizing and forecasting Maintenance for Transmission Facilities,
- Extending the useful life of the Transmission Facilities while maintaining their inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum total cost for Maintenance and Outages.

The ISO Maintenance Standards address the following topics:

- Transmission Facilities Covered by the ISO Maintenance Standards;
- Availability Measures ;
- Availability Measure Targets;
- ISO Maintenance Guidelines for PTO Maintenance practices;
- Qualifications of Maintenance Personnel;
- Maintenance Record Keeping and Reporting;
- Establishment of a Maintenance Coordination Committee;
- Process for the Revision of the ISO Maintenance Standards;
- Incentives and Penalties for PTO Availability Performance;
- Compliance with Laws and Regulations; and
- Dispute Resolution.

For certain aspects of Maintenance, these Standards delineate specific requirements and responsibilities (e.g., requirements for PTO inspection and Maintenance records), for others they provide guidelines (e.g., contents of PTO Maintenance Practices documents), and for others they describe processes (e.g., review process for PTO Maintenance Practices documents) to be enacted to achieve the desired results.

Flexibility in establishing ISO Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, the ISO Maintenance Standards are founded on two basic precepts: 1) the effectiveness of each PTO's Maintenance will be gauged through an Availability performance monitoring system, and 2) the adequacy of each PTO's Maintenance Practices will be assessed through ISO review. Each PTO's Maintenance Practices will serve as the ISO's Maintenance Standards for the Transmission Facilities covered therein. The PTO Maintenance Practices ensure a reasonable level of Maintenance during the short term while Availability is used to monitor long term performance.

It is the belief of the ISO Maintenance Standards task force that it is impractical for the ISO to develop and/or impose on the PTO's a single uniform set of detailed descriptions of practices delineating condition or time-based schedules for various Maintenance activities that account for the myriad equipment, operating conditions, and environmental conditions within the ISO grid. For this reason, the ISO Maintenance Standards provide ISO Maintenance Guidelines to be followed by each PTO in preparing PTO Maintenance Practices for its Transmission Facilities.

2.2. Availability

ISO grid reliability is a function of the Availability of Transmission Facilities owned and operated by its PTO's. The key to the effectiveness of the ISO Maintenance Standards is the establishment of a consistent measure of Transmission Facility Availability (Availability Measures) and the initial setting of the Availability Measure Targets as well as periodic revisions of those targets. By measuring Availability the ISO is able to monitor the effectiveness of Maintenance. While the ISO is concerned with grid reliability, reliability is a function of a complex set of variables including the accessibility of alternative load paths, speed and sophistication of protective equipment, and the Availability of Transmission Line Circuits, and therefore is indirectly related to Maintenance. Thus, Availability will be the principal determinant of each PTO's performance under the ISO Maintenance Standards.

When using Availability as a gauge of Maintenance adequacy, several things must be kept in mind to avoid misinterpreting performance. The most important consideration is that across the ISO grid, the vast majority of all Forced Outages$^{(IMS)}$ are due to random/chance events that cannot be controlled by Maintenance. It is important to recognize that only a small percentage of all Forced Outages$^{(IMS)}$ can be controlled through Maintenance (i.e. activities that do not change the basic configuration of Transmission Facilities). This principle assumes the PTO is performing a reasonable level of Maintenance consistent with Good Utility Practice. If an unreasonably low level of Maintenance is performed for a sufficient period of time, Availability will decline. However, if a level of Maintenance is being performed, consistent with Good Utility Practice, increasing Maintenance activities by a significant order will not result in a corresponding increase in Availability. Thus, while Maintenance is important to ensuring Availability, drastic increases in Maintenance will not lead to substantial improvements in Transmission Facility Availability and associated grid reliability.

A variety of techniques can be used to monitor performance, however techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of performance. To account for random/chance variations while enabling monitoring for shifts and trends in performance, control charts have been widely accepted as an effective means for monitoring performance. Control charts are statistically-based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge the adequacy of performance. Availability is affected by several factors only one of which is Maintenance. In fact, for most Transmission Line Circuits only a small fraction of Forced Outages(IMS) can be attributed to phenomenon that could be controlled or avoided through Maintenance. Many more Forced Outages(IMS) are attributable to random/chance events than Maintenance-related items. Therefore, while monitoring Availability as a gauge of Maintenance adequacy is useful for evaluating long term trends, care must be taken to avoid reading too much into the correlation of Availability to Maintenance since so many additional variables also impact Availability.

The fundamental performance measures selected as the basis for developing an Availability performance monitoring system are the annual accumulated duration and frequency of certain types of Outages for each Transmission Line Circuit under the ISO's Operational Control. To enhance the Availability performance monitoring system's use as a gauge of Maintenance adequacy, it was necessary to exclude certain Outage(IMS) types from the determination of the performance measures. Those excluded Outages are:

- Scheduled Outages;
- Outages caused by events originating outside the PTO's system; and
- Outages demonstrated to have been caused by earthquakes.

Additionally, the Forced Outage(IMS) duration has been capped at 72 hours so that excessively long Forced Outages(IMS) do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage(IMS) duration. This is not to say that an excessively long Forced Outage(IMS) is not a concern. Rather, such Forced Outages(IMS) should be investigated to assess the reasons for their extended duration.

The performance monitoring system requires use of separate control charts for each Voltage Class and PTO. Existing Forced Outage(IMS) data contains significant differences in the Availability performance between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. However, regardless of the cause of the differences, review of the Forced Outage(IMS) data makes it eminently apparent that the performance differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts will be constructed to provide a complete representation of historical Availability performance, and to provide a benchmark against which future performance can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage(IMS) frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage(IMS) duration for those Transmission Line Circuits which experience Forced Outages(IMS); and
- The annual proportion of Transmission Line Circuits that experienced no Forced Outages(IMS).

These three control charts will assist the ISO and PTO's in assessing the performance of Voltage Classes over time. To accommodate this process on a cumulative basis data are made available to the ISO by each PTO at the beginning of a new year to assess the performance of the past years.

2.3. ISO Maintenance Guidelines

Two specific requirements regarding Maintenance documentation have been incorporated into the ISO Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance practices (PTO Maintenance Practices) to the ISO. Second, these standards require that each PTO maintain Maintenance records and make those records available to the ISO in order to demonstrate compliance with each element of its PTO Maintenance Practices.

To outline the fundamental requirements for, and to promote consistency in the PTO Maintenance Practices, these standards provide guidelines for the preparation and maintenance of the PTO Maintenance Practices. These ISO Maintenance Guidelines provide for flexibility in approach to Maintenance, but also require the description of certain specific Maintenance practices. The guidelines require that the PTO's provide descriptions of the various Maintenance activities, schedules and condition triggers for performing the Maintenance, and samples of any checklists, forms, or reports used for Maintenance activities.

2.4. Data Standards

To facilitate processing of Outage$^{(IMS)}$ data for the Availability performance monitoring system, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The ISO and PTO's have committed to developing standardized formats for transmitting Outage$^{(IMS)}$ data to the ISO for the Availability performance monitoring system. These standard formats are to be finalized within the first 60 days of 1998. Additionally, the ISO and PTO's have agreed to develop and implement a standard Maintenance reporting system by the end of the third year of operation of the ISO. This system will provide for consistent gathering of information that can be used as the basis for optimizing and forecasting maintenance of Transmission Facilities. The development of such a Maintenance reporting system is consistent with fostering the spirit of cooperation among the ISO and the PTO's as it may eventually aid in the resolution of performance problems, and provide the basis for research on an ISO grid-wide basis to identify opportunities to enhance Transmission Facility Maintenance.

2.5. Applicability of Incentives and Penalties

Cooperation and collaboration among the PTOs responsible for ensuring the Availability of the Transmission Facilities comprising the ISO grid are needed to ensure the most reliable grid possible. Therefore, the ISO Maintenance Standards task force believes that a formal program of incentives and penalties tied purely to PTO Maintenance may hinder needed cooperation among PTOs. As a result, the ISO Maintenance Standards task force recommends that no such program be instituted initially by the ISO.

Further, the task force recognizes the need for the ISO to enforce reasonable Maintenance to ensure Availability in the case that: 1) a PTO exhibits degradation in Availability performance due to Maintenance, 2) a PTO does not comply with its PTO Maintenance Practices, or 3) a PTO is grossly or willfully negligent with regards to Maintenance. Therefore, it is the position of the ISO Maintenance Standards task force that it is reasonable for the ISO to establish penalties for such conditions. In the absence of a formal program of incentives and penalties, the task force acknowledges the ISO's right to pursue sanctions for cause on a case by case basis.

Availability is a useful and tractable means for monitoring performance, however, the electric utility industry as a whole has little experience in using Availability to gauge the adequacy of Maintenance. Further, because the industry in general has not carefully managed historical Outage(IMS) data to the degree that is necessary to make them useful for performance monitoring, there are varying limitations with regards to the accessibility and reliability of Outage(IMS) data among PTOs. Also, the impact on

Availability when a new entity, namely the ISO, assumes Operational Control of the grid is unknown. Thus, it is the position of the ISO Maintenance Standards task force that the Availability performance monitoring system will be implemented and used to gauge Availability performance beginning on the ISO Operations Date. However, the system needs to be used and updated during a five year phase in period to be considered for use in a program of incentives and penalties for Availability performance.

Availability is a function of several variables including Transmission Facility Maintenance, capital improvements, and improvements in restoration practices. If a PTO is exercising a reasonable level of Maintenance, yet the Availability performance of a Voltage Class or individual Transmission Line Circuit is inadequate for the purposes of the ISO grid, then capital improvements or improvements in restoration practices may lead to greater Availability improvements than increased Maintenance. Therefore, assessing incentives and penalties on the basis of Availability as influenced by all of these variables may be a reasonable approach for influencing PTO's to improve the Availability of their Transmission Facilities where such improvements can be justified.

3. TRANSMISSION FACILITIES COVERED BY THE ISO MAINTENANCE STANDARDS

All Transmission Facilities transferred to the ISO, pursuant to the Transmission Control Agreement, shall be maintained in accordance with the ISO Maintenance Standards.

4. AVAILABILITY STANDARD

4.1. Introduction

The ISO shall monitor and measure each PTO's Availability for the Transmission Line Circuits under ISO Operational Control. The ISO shall use an Availability measurement system which consists of two primary components: 1) measures of the annual performance of each Voltage Class based on the performance of each of the Transmission Line Circuits comprising the Voltage Class, i.e. the Availability Measures; and 2) a set of threshold performance criteria for each Voltage Class, i.e. Availability Measure Targets. The Availability Measure Targets will be used to gauge the adequacy of the PTO's annual performance for each Voltage Class. Each PTO shall make an annual report to the ISO within 90 days from the end of each calendar year that describes its compliance with the Availability Measure Targets. In its report to the ISO, supporting data based on Outage$^{(IMS)}$ records shall be included, justifying the Availability Measures reported for each Voltage Class.

4.2. Availability Measures

4.2.1. Calculation of Availability Measures for Individual Transmission Line Circuits

The calculation of the Availability Measures will be performed utilizing Outage$^{(IMS)}$ data through December 31 of each year. Separate Forced Outage$^{(IMS)}$ frequency and accumulated Forced Outage$^{(IMS)}$ duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each

Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Outage data for the calendar year in question.

Forced Outage$^{(IMS)}$ Frequency:

The Forced Outage$^{(IMS)}$ frequency (f_{ik}) of the ith Transmission Line Circuit shall equal the total number of Forced Outages$^{(IMS)}$ that occurred on the ith Transmission Line Circuit during the calendar year k. See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages$^{(IMS)}$ on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage$^{(IMS)}$ with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage$^{(IMS)}$ and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e. 61 seconds or more, followed by another Forced Outage$^{(IMS)}$, then these should be counted as two Forced Outages$^{(IMS)}$. Multiple Forced Outages$^{(IMS)}$ occurring as a result of a single event should be handled as multiple Forced Outages$^{(IMS)}$ only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage$^{(IMS)}$.

2. If a Transmission Line Circuit, e.g. a new Transmission Line Circuit, is only in service for a portion of a year, the Forced Outage$^{(IMS)}$ frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire year, i.e. the Outage$^{(IMS)}$ data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage$^{(IMS)}$ Duration:

The accumulated Forced Outage$^{(IMS)}$ duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year k:

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ (total number of Forced Outage$^{(IMS)}$ minutes) for the ith Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year k.

f_{ik} = Forced Outage$^{(IMS)}$ frequency as defined above for calendar year k.

o_{ijk} = duration in minutes of the j^{th} Forced Outage$^{(IMS)}$ which occurred during the k^{th} calendar year for the i^{th} Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages$^{(IMS)}$ shall be capped as described in Section 4.2.2. "Capping of Forced Outage$^{(IMS)}$ Duration" for the purposes of calculating the Availability Measures . In addition, certain types of events/Outages shall be excluded from the calculations of the Availability Measures as described in Section 4.2.3 "Excluded Events".

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Outage$^{(IMS)}$ data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO the PTO shall provide recommendations regarding how the Availability Measures and Availability Measure Targets should be modified to ensure they remain consistent with the modified Transmission Line Circuit identification or Outage$^{(IMS)}$ data reporting scheme, and that they provide an appropriate gauge of performance.

4.2.2. Capping of Forced Outage$^{(IMS)}$ Durations

The durations of individual Forced Outages$^{(IMS)}$ which exceed 72 hours (4320 minutes) shall each be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage$^{(IMS)}$ duration.

4.2.3. Excluded Events

The following types of events/Outages shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages which are scheduled, reviewed and approved by the ISO in accordance with the Transmission Control Agreement, and

- Forced Outages(IMS) which: 1) were caused by events outside the PTO's system including those Outages which originate in other TO systems, other electric utility systems, or customer equipment, and 2) those Forced Outages(IMS) which can be demonstrated to have been caused by earthquakes.

4.3. Targets for Availability Performance

The Availability Measure Targets described herein shall be phased in over a period of five years beginning on the ISO Operations Date. The adequacy of each PTO's Availability performance shall be monitored through the use of charts on which are plotted indices reflecting annual Availability performance. These charts, called control charts as shown in Figure 4.3.1, are defined by a horizontal axis with a scale of years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability performance for each Voltage Class within each PTO's system:

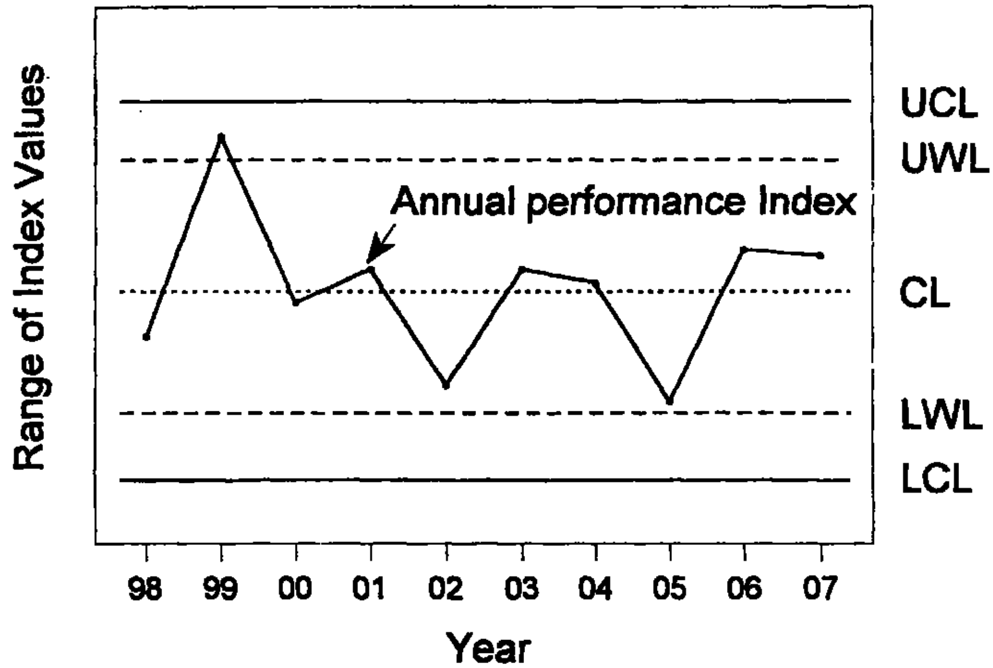

Figure 4.3.1 Sample Control Chart

- Index 1: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- Index 2: Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS).
- Index 3: Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS).

The control charts incorporate a center line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages(IMS), the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section 4.3.2. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the Normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number("seed") for it's random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section 4.3.3.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. Maintenance procedures recommended by the MCC and approved by the ISO Governing Board will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply.More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the MCC and approved by the ISO Governing Board for use in creating the control charts .

4.3.1. Calculations of Annual Availability Performance Indices for Individual Voltage Classes

Separate annual Availability performance indices shall be calculated for each Voltage Class and PTO as described below utilizing the Availability Measures discussed in Section 4.2.

Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k} \sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages(IMS) /Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class in calendar year k. See Note 2, Section 4.2.1.

f_{ik} = frequency of Forced Outages(IMS) for the ith Transmission Line Circuit as calculated in accordance with Section 4.2.1 for calendar year k.

Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS) (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}} \sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages(IMS) during the calendar year k.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage(IMS) frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

d_{ik} = accumulated duration of Forced Outages(IMS) for the ith Transmission Line

Circuit having a Forced Outage(IMS) frequency Availability Measure (f_{ik}) greater than zero for calendar year k as calculated in accordance with Section 4.2.1.

Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS) (Index 3):

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages(IMS) for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class for calendar year k. See Note 2, Section 4.2.1.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage(IMS) frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

4.3.2. Development of Limits for Performance Control Charts

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits, Annual Average Accumulated Forced Outage(IMS) Duration for Transmission Line Circuits with Forced Outages(IMS), and Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)) on which the annual Availability performance indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Outage(IMS) data for the ten year period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. In the event that a PTO does not have reliable, continuously recorded Outage(IMS) data for this 10 year period, the PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, the PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO prior to February 1, 1998, or within 30 days after a TO becomes a PTO. The ISO shall periodically review the control chart limits and appropriately modify them when necessary in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

4.3.2.1. CLs

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability performance indices described in Section 4.3.1 except that the period for which data are to be included in the calculations is expanded from a single calendar year to the ten years, unless a shorter period is justified by the PTO, for the period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. To account for this change a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

<u>CL for Annual Transmission Line Circuit Forced Outage(IMS) Frequency</u>

$$CL_{fvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_k} f_{ik} \, / \, (\sum_{k=1}^{Y} N_k)$$

where

CL_{fvc} = center control line value for the Forced Outage(IMS) frequencies for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

Y = number of years prior to the ISO Operations Date (or the date a TO becomes a PTO) for which the PTO has reliable, continuously recorded Outage(IMS) data. Y=10 is preferred.

<u>CL for Annual Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS)</u>

$$CL_{dvc} = \sum_{k=1}^{Y}\sum_{i=1}^{N_{o,k}} d_{ik} / (\sum_{k=1}^{Y} N_{o,k})$$

where

CL_{dvc} = center control line value for accumulated Forced Outage(IMS) duration for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date (or the date a TO becomes a PTO) in which the Forced Outage(IMS) frequency (f_{ik}) was greater than zero.

CL for Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)

$$CL_{Pvc} = \frac{\sum_{k=1}^{Y}(N_k - N_{o,k})}{\sum_{k=1}^{Y} N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

4.3.2.2. UCLs, LCLs, UWLs and LWLs

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages(IMS) for Five or More Years

The UCLs , UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages(IMS) shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each years development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of lines per year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process, will be repeated 10,000 times in order to create a column of sampling means from the historical data base. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL(99.75), a LCL(0.25) a UWL(97.5), and a LWL(2.5). Thus, for one cycle, the limits are determined by resampling from the historical data base, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get 10 values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index 2 forming means for the median number of lines with Forced Outages$^{(IMS)}$ in this Voltage Class for the time period being evaluated. See **Bootstrapping - A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the Bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per year with a history of ten years. Furthermore, assume that about 15 Transmission Line Circuits per year experience Forced Outages. Therefore, there are 10 x 15 = 150 Forced Outage$^{(IMS)}$ durations available for bootstrap sampling. Place these 150 Forced Outage$^{(IMS)}$ durations in a column, say "outdur"... in a specified order . The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage$^{(IMS)}$ duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest to largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 lines over the ten years using the formulas in Section 4.3.2.1. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes

When data for less than four Transmission Line Circuits with Forced Outages$^{(IMS)}$ are available per year in a Voltage Class for fewer than five years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages$^{(IMS)}$ for five or more years. For example, if a Voltage Class has only two Transmission Line Circuits per year for five years, the data base will consist of 2*5 = 10 accumulated Forced Outage$^{(IMS)}$ durations assuming both Transmission Line Circuits experience a Forced Outage$^{(IMS)}$ or more per year. Resampling two values from the column of 10 yields only 10**2 = 100 possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data 10,000/100 = 100 times.

For the general case, let M = the number of accumulated Forced Outage$^{(IMS)}$ durations (or Forced Outage$^{(IMS)}$ frequencies) from the historical data base. If n is the median number of Transmission Line Circuits per year, there are M**n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing U enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e. at the 99.75, 0.25, 97. 5 and 2. 5 percentiles, respectively).

<u>UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Lines is > 125</u>

According to standard procedures for proportion control charts for voltage classes where the median number of lines in service is greater than 125 for any given year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the kth year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{Pvc} + 3S_{Pvc,k} \qquad\qquad LCL = CL_{Pvc} - 3S_{Pvc,k}$$

UWL and LWL are calculated by replacing the "3" above with a "2".

and

$$S_{Pvc,k} = \sqrt{CL_{Pvc}(1 - CL_{Pvc})/N_k}$$

where

$S_{Pvc,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages$^{(IMS)}$ for each (kth) year of the *Y* years prior to the ISO Operations Date, or the date a TO becomes a PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of Lines is less than or equal to 125 and greater than or equal to six.

The UCLs, LCLs, UWLs, and LWLs for the control charts for each voltage class shall be based on exact binomial probabilities for those voltage classes having equal to or more than six but less than or equal to 125 median transmission lines per year.

A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL contains about 99.5% and the UWL and LWL contains about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n$$

$$UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n$$

$$LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n$$

$$LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n$$

Where

P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas(i.e. P_2 = 0.9975 in the UCL formula and =0.025 in the LWL formula)

P_1 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas(e.g. if $P_1 = 0.74$ and is closest to the 99.75 percentile value and represents the 99 percentile then $P_1 = 0.74$ should be used in the UCL formula).

P_3 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas(e.g. if $P_3 = 0.82$ and is closest to the 99.75 percentile value and represents the 99.85 percentile then $P_3 = 0.82$ should be used in the UCL formula).

X_1 = The number of lines with no outages associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas.(e.g. If $P_1 = 0.74$ and represents the 99^{th} percentile for the case where 78 lines didn't have any outages then $X_1 = 78$ should be used in the UCL formula).

n = The median number of lines that are in service in a given year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas

More information on the calculations of the proportion control chart limits is in the current ISO Transmission Facility Availability Performance Monitoring System Handbook.

4.3.3. Evaluation of Availability Performance

The control charts shall be reviewed annually in order to evaluate Availability performance. The annual performance evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual year, shifts in longer term performance, and trends in longer term performance.

Tests

- **Test 1:** The index value for the current year falls outside the UCL or LCL.
- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this says that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short term change or jump in the average level. Tests 2 and 4 are looking for long term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three year period. Together the four tests allow the ISO to monitor the availability performance of a Voltage Class for a PTO.

If none of these tests indicates that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table 4.3.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that year if necessary. However, it is suggested that unless the number of lines changes by more than 30% from the previous year, the use of the median number of lines should continue. Consider an example. Suppose after the control chart has been prepared for a Voltage Class, next year's data arrive with the number of lines 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that year.

For the special case where only one Transmission Line Circuit has a Forced Outage$^{(IMS)}$ in a Voltage Class during a year, the assessment process for Index 2 is as follows. If Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information on the individual and moving range control charts can be found in the user manuals of the statistical software approved by the ISO for use in creating the control charts

If the ISO deems that the Availability Measure Targets should be modified, they shall be modified in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

Table 4.3.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test		Performance Status Indicated by Test Results	
	Number	Results	Improvement	Degradation
Annual Average Forced Outage[(IMS)] Frequency	1	value is above the UCL		✔
		value is below the LCL when LCL>0	✔	
	2	v1 or more consecutive values above the CL		✔
		v2 or more consecutive values below the CL	✔	
	3	2 out of 3 values above the UWL		✔
		2 out of 3 values below the LWL	✔	
	4	6 consecutive values increasing		✔
		6 consecutive values decreasing	✔	
Annual Average Accumulated Forced Outage Duration	1	value is above the UCL		✔
		value is below the LCL when LCL>0	✔	
	2	v1 or more consecutive values above the CL		✔
		v2 or more consecutive values below the CL	✔	
	3	2 out of 3 values above the UWL		✔
		2 out of 3 values below the LWL	✔	
	4	6 consecutive values increasing		✔
		6 consecutive values decreasing	✔	
Annual Proportion of Transmission Line Circuits with No Forced Outages	1	value is above the UCL	✔	
		value is below the LCL when LCL>0		✔
	2	v1 or more consecutive values above the CL	✔	
		v2 or more consecutive values below the CL		✔
	3	2 out of 3 values above the UWL	✔	
		2 out of 3 values below the LWL		✔
	4	6 consecutively increasing values	✔	
		6 consecutively decreasing values		✔

4.4. Outage(IMS) Data Reporting

All Outages which interrupt the flow of power on PTO Transmission Facilities under the ISO's Operational Control shall be reported by the PTO to the ISO. Outage(IMS) reports shall include the date, start time, end time, affected Transmission Facility, and the probable cause of the Outage(IMS) if known.

5. ISO MAINTENANCE GUIDELINES AND PTO MAINTENANCE PRACTICES

5.1. Introduction

The ISO with due consideration for the recommendations of the Maintenance Coordination Committee shall establish, revise as needed, and maintain guidelines for Transmission Facilities Maintenance as described in Section 5.2 of this document. These ISO Maintenance Guidelines shall be followed by each PTO in preparing a written description of, and updating as necessary, its PTO Maintenance Practices which may be performance-based, time-based, or both, as may be appropriate for each Transmission Facility under the ISO's Operational Control. The PTO Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including technological innovations and facility importance.

5.2. ISO Maintenance Guidelines for Preparation of PTO Maintenance Practices

5.2.1. Transmission Line Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the following transmission line Maintenance activities:

a) Patrol/Inspection

- Routine
- Detailed
- Emergency

b) Vegetation Management/Right-of-Way Maintenance

As may be appropriate for the specific facilities and equipment under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail Maintenance activities for various attributes of the transmission lines including, but not limited to:

- Structures: wood pole, lattice steel, tubular steel, and concrete pole
- Guys/Anchors
- Foundations
- Insulators
- Conductor and Shield Wire
- Conductor and Shield Wire Clearances
- Hardware and Fittings
- Disconnects/Pole-top Switches
-
- Encroachments/Unauthorized Attachments
- Underground Transmission Components

5.2.2. Station Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the Maintenance of the following equipment and attributes of Stations:

- Circuit Breakers
- Insulators/Bushings/Arrestors
- Transformers
- Regulator
- Disconnect Switches
- Metering
- Battery Systems
- Reactive Devices

- Relaying
- Communication Facilities
- Station Auxiliary Equipment
- Direct Current Transmission Components
- Structures/Foundations

As may be appropriate for the specific equipment in and configurations of the PTO's Stations under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail various Maintenance activities for the attributes and potential conditions of the Stations including, but not limited to:

- Visual Inspection of/for: fences and grounds, vegetation, clearances, tracking, abnormal heating, cracks/chips, noise, leaks, blown fuses, and bulging of equipment cases
- Oil Containment
- Insulation Mediums
- Equipment Contacts
- Mechanical Timing
- Contamination Control
- Testing and Calibration
- Cooling Systems
- Measuring Devices
- Lubrication and Overhaul of Moving Parts

5.2.3. Descriptions of PTO Maintenance Practices

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The PTO's Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms which may be required for the activity. Where appropriate, the PTO's

Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility or component. Where appropriate, the PTO's Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission Facilities.

5.3. Review and Adoption of PTO Maintenance Practices

5.3.1. Initial Adoption of PTO Maintenance Practices

5.3.1.1. Submittal of Information by the Prospective PTOs to the ISO

Each prospective PTO shall provide the ISO with information concerning its PTO Maintenance Practices pursuant to Section 5.2 of this Appendix C. This information shall be prepared so as to be easily interpreted by the ISO and shall provide sufficient detail to assess the adequacy and reasonableness of the PTO Maintenance Practices, using the criteria referenced in Section 14.1 of the Transmission Control Agreement.

5.3.1.2. Review of the PTO Maintenance Practices by the ISO

The ISO shall review the information provided pursuant to Section 5.3.1.1 of this Appendix C and may provide to a PTO a recommendation for an amendment to the PTO Maintenance Practices in question by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. To the extent there are no recommendations, the PTO Maintenance Practices will be adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

Any agreement, in respect of PTO Maintenance Practices, reached between the ISO and a prospective PTO prior to the ISO Operations Date shall be adopted by the ISO for purposes of this Section 5.3.1.

5.3.2. Proposals for Amendments to the PTO Maintenance Practices

5.3.2.1. Amendments Proposed by the ISO

The ISO shall periodically review each PTO's Maintenance Practices having regard to the ISO Maintenance Standards, as amended and revised from time to time pursuant to Sections 7 and 8 of this Appendix C. Following such a review, and after considering the Section 348 Criteria, the ISO may recommend an amendment of PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with 5.3.3 of this Appendix C. Except as provided in Section 5.3.3.4 of this Appendix, the effective date shall be no earlier than 30 days from the date of such notice.

5.3.2.2. Amendments Proposed by a PTO

A PTO may provide to the ISO its own recommendation for an amendment to its PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. The effective date shall be no earlier than 30 days from the date of such notice.

5.3.3. Disposition of Recommendations

5.3.3.1. If the ISO or a PTO makes a recommendation to amend the PTO Maintenance Practices of a PTO, as contemplated in Sections 5.3.1 or 5.3.2 of this Appendix C, the other Party shall have 30 days to provide a notice to the recommending party, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not agree with the recommended amendment. If it fails to provide such notice of disagreement, the recommended amendment shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified in the notice of the recommended amendment, which date shall be no earlier than 30 days from the date of issuance of such notice of amendment.

5.3.3.2. If a PTO makes a recommendation to amend its PTO Maintenance Practices, and if the ISO provides notice within the 30 days specified in the first paragraph of this Section 5.3.3, pursuant to Section 26.1 of the Transmission Control Agreement, that the ISO, having regard for the Section 348 Criteria, does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing PTO Maintenance Practices shall be retained. Either Party may, however, seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.3. If the ISO makes a recommendation to amend the PTO Maintenance Practices of a PTO, the PTO Maintenance Practices, as amended pursuant to the ISO recommendation, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified by the ISO in its notice of recommended amendment. If the PTO gives notice of a disagreement within the 30 days specified in the first paragraph of this Section 5.3.3, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If a resolution is not reached, either Party may seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment, and the ISO shall not unreasonably withhold its consent to such a request, having regard to the Section 348 Criteria. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.4. If the ISO determines in its judgment, after considering the Section 348 Criteria, that prompt action is required to avoid a substantial risk to safety or reliability, it may direct a PTO to implement certain temporary maintenance activities in a period of less than 30 days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any such maintenance practice advisories shall specify why implementation solely under Section 5.3.3.3 is not sufficient to avoid a substantial risk to safety or reliability including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. If time permits, the ISO shall consult with the relevant PTO before issuing a maintenance practice advisory. Upon receiving such an advisory, a PTO shall implement the temporary maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary maintenance activities as fully as possible. All such maintenance practice advisories shall cease to have effect in 90 days after issuance or such earlier period as the ISO provides in its notice. Renewal or extension of such temporary maintenance requirements beyond 90 days shall require a recommendation process pursuant to Section 5.3.3.2 or Section 5.3.3.3 of this Appendix.

5.3.3.5. Nothing in this Transmission Control Agreement shall be construed to limit the ISO's authority under Public Utilities Code Section 348 to adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under ISO control.

5.4. Qualifications of Personnel

All Maintenance of Transmission Facilities under the ISO's Operational Control shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

The four elements of the ISO's requirements for Maintenance record keeping and reporting are as follows:

a) The PTO will maintain records of its Maintenance activities, as set forth in Section 6.1.
b) The PTO will provide certain Maintenance records to the ISO, as set forth in Section 6.2.
c) The PTO will allow the ISO to visit Transmission Facilities, as set forth in Section 6.3.
d) The PTO will make records for Maintenance activities available to the ISO, as set forth in Section 6.4.

In addition, the Maintenance Coordination Committee shall annually review the requirements of this section of the ISO Maintenance Standards and shall seek to standardize reasonable record keeping, reporting and information-sharing requirements sufficient to support ISO regulatory reporting needs.

6.1. The PTO Will Maintain Records of its Maintenance Activities

The PTO shall maintain records demonstrating compliance with each element of the PTO Maintenance Practices. The PTO's Maintenance records shall be maintained for five years, or for one year after specific corrective Maintenance activities identified by the PTO are completed, whichever is longer.

Each PTO's inspection records shall, at a minimum, identify the inspector, the Transmission Facility inspected, the inspection date(s), the findings of the inspection, recommended Maintenance activities, and the priority of the Maintenance recommendations.

Each PTO's Maintenance records shall, at a minimum, identify the person responsible for performing the Maintenance, the date of the Maintenance, the Transmission Facility maintained, and a description of the Maintenance that was performed.

6.2. The PTO Will Provide Certain Maintenance Records to the ISO

By the end of the third year of operation of the ISO, the ISO and PTO's shall develop and implement a standard Maintenance reporting system based on the recommendations of the Maintenance Coordination Committee. Until the standard Maintenance reporting system is implemented, the PTO shall provide the ISO, on an annual basis, records for substantial Maintenance as limited by the following list:

a) Transmission Line Maintenance

- Patrol/Inspection
- Vegetation Management/Right-of-way Maintenance
- Structures: Wood pole, lattice steel, tubular steel, concrete pole

- Insulators (Contamination Control)

b) Station Maintenance

- Circuit Breakers
- Transformers
- Insulators/Bushings/Arrestors (Contamination Control)
- Regulators
- Relaying

If the PTO maintains records in a manner that includes additional information, such records may be submitted in that manner.

6.3. The PTO Will Allow the ISO to Visit Transmission Facilities

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement.

6.4. The PTO Will Make Records for Maintenance Activities Available to the ISO

The PTO shall make all Maintenance records for a Voltage Class available to the ISO upon the request of the ISO if the annual evaluation of performance per Section 4.3.3 demonstrates degradation in the PTO's Availability performance. Upon identification of degradation, the PTO's reporting of Maintenance data to the ISO shall continue until a subsequent year's annual performance returns to a non-degraded level.

If a review of available records by the ISO indicates inconsistencies from the PTO Maintenance Practices relating to a specific activity, then the ISO may request that the PTO provide further documentation and explanation related to those Maintenance activities.

7. MAINTENANCE COORDINATION COMMITTEE

7.1. Maintenance Coordination Committee Functions

The ISO shall seek to establish and then appropriately convene a Maintenance Coordination Committee for the purposes of periodically conveying information, seeking input from other PTOs and interested stakeholders regarding ISO Maintenance Standards as well as making recommendations with respect to proposed amendments and revisions of the ISO Maintenance Standards.

7.2. Consensus

Although the role of the Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members, and promulgate practices, standards and protocols consistent with relevant laws and regulations.

8. REVISION OF ISO MAINTENANCE STANDARDS

The ISO, PTO's, or any interested stakeholder may submit proposals to amend or revise the ISO Maintenance Standards. Any change proposal shall be submitted to the Maintenance Coordination Committee for consideration in accordance with Section 7.0, "Maintenance Coordination Committee," of this document. Recommendations for revisions of the ISO Maintenance Standards shall be submitted by the Maintenance Coordination Committee to the ISO for approval.

9. INCENTIVES AND PENALTIES

Any incentives and penalties relating to this Appendix shall be established in accordance with the Transmission Control Agreement, the ISO Tariff and ISO Protocols after consultation between the PTO and the ISO, and approval by the FERC. No incentives, penalties or sanctions may be imposed relating to this Appendix unless a

Schedule providing for such incentives, penalties or sanctions has first been filed with and made effective by the FERC. Nothing in this Appendix shall be construed as waiving the rights of the PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the PTO.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain its Transmission Facilities that are under the Operational Control of the ISO in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable protocols, laws, and regulations, in order to achieve the Availability Measure Targets set by the ISO.

10.1 SAFETY

It is of paramount importance that the PTO ensure the safety of personnel, and the public in performing these Maintenance duties and that the ISO operate the system in a manner which is compatible with the priority of ensuring safety. The PTO shall ensure the safety of personnel and the public in accordance with jurisdictional agency regulations and ensure the reliability of the system in accordance with CAISO Maintenance Standards. In the event there is conflict between the safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any disputes between the ISO and PTO regarding issues related to the Maintenance, and Availability of Transmission Facilities under the Operational Control of the ISO shall be resolved in accordance with the Section 15 of the Transmission Control Agreement.

TRANSMISSION CONTROL AGREEMENT

APPENDIX D

Master Definitions Supplement

Actual Adverse Tax Action	A plan, tariff provision, operating protocol, action, order, regulation or law issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, that likely adversely affects the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO or that, with the passage of time, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, no Actual Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Actual Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.

Adverse Tax Action Determination	A determination by a Tax Exempt Participating TO, as supported by (i) an opinion of its (or its joint action agency's) nationally recognized bond counsel, or (ii) the IRS (e.g., through a private letter ruling received by a Tax Exempt Participating TO or its joint action agency), that an Impending Adverse Tax Action or an Actual Adverse Tax Action has occurred.
AGC (Automatic Generation Control)	Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.

Applicable Reliability Criteria	The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.
Applicants	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.
Approved Maintenance Outage	A Maintenance Outage which has been approved by the ISO through the ISO Outage Coordination Office.
Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Business Day	A day on which banks are open to conduct general banking business in California.
Congestion	A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously. "Congested" shall be construed accordingly.

Congestion Management	The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.
Control Area	An electric power system (or combination of electric power systems) to which a common AGC scheme is applied in order to: i) match, at all times, the power output of the Generating Units within the electric power system(s), plus the Energy purchased from entities outside the electric power system(s), minus Energy sold to entities outside the electric power system, with the Demand within the electric power system(s); ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and iv) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.
CPUC	The California Public Utilities Commission, or its successor.

Critical Protective System	Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.
Day-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO, the PX and other Scheduling Coordinators and which closes with the ISO's acceptance of the Final Day-Ahead Schedule.
Demand	The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.
Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section

212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.

EMS (Energy Management System) A computer control system used by electric utility dispatchers to monitor the real time performance of the various elements of an electric system and to control Generation and transmission facilities.

Encumbrance A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.

End-Use Customer or **End-User**	A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.
Energy	The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Existing Contracts	The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.
Existing Rights	Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.
Facilities Study Agreement	An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries

agree to reimburse the Participating TO for the cost of a Facility Study.

Facility Study	An engineering study conducted by a Participating TO to determine required modifications to the Participating TO's transmission system, including the cost and scheduled completion date for such modifications that will be required to provide needed services.
FERC	The Federal Energy Regulatory Commission or its successor.
FIITC (Firm Import Interconnection Transmission Capacity)	The amount of firm transmission capacity in MW associated with transmission facilities owned by a Participating TO or contracted to the Participating TO under an Existing Contract, which allows Generating Units that are not directly interconnected with that Participating TO's transmission or distribution system to deliver Energy to that Participating TO. For each month of the Self-Sufficiency Test Period, FIITC shall include the maximum amount of requirements and bundled power sale capacity purchased by the Participating TO from the transmission owner to which it is physically interconnected during the hour in which the Monthly Peak Load of the Participating TO occurs.

Forced Outage	An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.
FPA	Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.
Generating Unit	An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Control Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and (c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).
Generation	Energy delivered from a Generating Unit.
Generator	The seller of Energy or Ancillary Services produced by a Generating Unit.
Good Utility Practice	Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of

reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Hour-Ahead Market The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO, the PX and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.

Hydro Spill Generation Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.

Impending Adverse Tax Action A proposed plan, tariff, operating protocol, action, order, regulation or law that, if issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, that with respect to a proposed federal law, such proposed law must first have been approved by (i) one of the houses of the United States Congress and (ii) at least one committee or subcommittee of the other house of the United States Congress; provided further, however, no Impending Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Impending Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.

Interconnection Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.

Interconnection Agreement A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

IRS	The United States Department of Treasury, Internal Revenue Service, or any successor thereto.
ISO (Independent System Operator)	The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
ISO ADR Procedures	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
ISO Code of Conduct	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in Exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in Exhibit B to the ISO bylaws.
ISO Control Center	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.
ISO Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the ISO's Operational Control.
ISO Governing Board	The Board of Governors established to govern the affairs of the ISO.
ISO Grid Operations Committee	A committee appointed by the ISO Governing Board pursuant to Article IV, Section 4 of the ISO bylaws to

	advise on additions and revisions to its rules and protocols, tariffs, reliability and operating standards and other technical matters.
ISO Operations Date	The date on which the ISO first assumes Operational Control of the ISO Controlled Grid.
ISO Outage Coordination Office	The office established by the ISO to coordinate Maintenance Outages in accordance with Section 2.3.3 of the ISO Tariff.
ISO Protocols	The rules, protocols, procedures and standards promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.
ISO Register	The register of all the transmission lines, associated facilities and other necessary components that are at the relevant time being subject to the ISO's Operational Control.

ISO Tariff	The California Independent System Operator Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Criteria	Reliability criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Maintenance Outage	A period of time during which an Operator takes its facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment.

Market Participant	An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.
Municipal Tax Exempt TO	A Transmission Owner that has issued Municipal Tax Exempt Debt with respect to any transmission facilities, or rights associated therewith, that it would be required to place under the ISO's Operational Control pursuant to the Transmission Control Agreement if it were a Participating TO.
NERC	The North American Electric Reliability Council or its successor.

Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WSCC operating criteria.
Non-Converted Rights	Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.
Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
NRC	The Nuclear Regulatory Commission or its successor.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.
Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.

Operator	The operator of facilities comprised in the ISO Controlled Grid or Reliability Must-Run Units.
Outage	Disconnection or separation, planned or forced, of one or more elements of an electric system.
Participating Generator	A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid and which has undertaken to be bound by the terms of the ISO Tariff.
Participating TO	A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA.
Physical Scheduling Plant	A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes

Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.

PMS (Power Management System) The ISO computer control system used to monitor the real time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.

Preferred Schedule The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the

	location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule will be balanced with respect to Generation, Transmission Losses, Load and trades between Scheduling Coordinators.
Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Regulatory Must-Run Generation	Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse

releases and water quality requirements, irrigation and water supply requirements, or the requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.

Reliability Criteria	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
Reliability Must-Run Unit	A Generating Unit which is the subject of the contract between the Generator and the ISO under which, in return for certain payments, the ISO is entitled to call upon the owner to run the unit when required by the ISO for the purposes of the reliable operation of the ISO Controlled Grid.
RTG (Regional Transmission Group)	A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.

Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.
Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
Self-Sufficiency or **Self-Sufficient**	A Participating TO for which the sum of its Dependable Generation and its FIITC is greater than or equal to its Monthly Peak Load.
Settlement Account	An account held at a bank situated in California, designated by a Scheduling Coordinator or a Participating TO pursuant to the Scheduling Coordinator's SC Agreement or in the case of a Participating TO, Section 2.2.1 of the TCA, to which the ISO shall pay amounts owing to the Scheduling Coordinator or the Participating

	TO under the ISO Tariff.
System Emergency	Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.
System Planning Studies	Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.
System Reliability	A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax-Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs

	will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.
UDC (Utility Distribution Company)	An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.
Uncontrollable Force	Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, breakage, or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military

	or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence.
Voltage Support	Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.
WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange among the ISO, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.
Wheeling Out	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Wheeling Through	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating

Unit located outside the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.

Withdraw for Tax Reasons or Withdrawal for Tax Reasons In accordance with Section 3.4 of this Agreement, withdrawal from this Agreement, or withdrawal from the ISO's Operational Control of all or any portion of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the Tax Exempt Debt that is the subject of an Impending Adverse Tax Action or an Actual Adverse Tax Action.

WSCC (Western System Coordinating Council) The Western Systems Coordinating Council or its successor.

TRANSMISSION CONTROL AGREEMENT

APPENDIX E

Nuclear Protocols

DIABLO CANYON NUCLEAR POWER PLANT UNITS 1 & 2

REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY REVISION 1

DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

OVERVIEW

The DCPP Operating License and Technical Specifications require two physically independent sources (not necessarily on separate right of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both sources is acceptable. Each of these sources shall be designed to be available in sufficient time following a loss of all DCPP onsite alternating current power supplies and the other offsite electric power circuit. One of these sources shall be designed to be available within a few seconds following a loss-of-coolant accident. For DCPP, the sources available within seconds are the 230 kV grid interface and the second source is the 525 kV grid interface.

During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads (safety related and non-safety related) are transferred to the 230 kV grid. In addition DCPP has a delayed transfer capability to the 525 kV grid. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.

The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the

DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If either source of the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP units(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if either source is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition, which renders the offsite power unavailable for safe shutdown and emergency purposes.

In specific terms, the offsite power supply voltages (at the DCPP switchyards) must stay within the range of 207 kV to 240 kV and 525 kV to 545 kV under post accident operating conditions. During normal operation, the 230 kV voltage must maintain above 207 kV such that when DCPP transfers its load from the onsite source to the offsite source the voltage does not decrease below 207 kV. During normal operation, the 230 kV voltage at DCPP 230 kV switchyard should meet the 230 kV voltage requirements identified in PG&E Operating Instruction O-23. Otherwise, that offsite power source may be considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip does not impair the operability of the offsite power system. Therefore, following a trip of a DCPP unit (i.e., the unit breakers open) and assuming the other DCPP unit was already shutdown, the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the unit trip. If this condition cannot be met, then the offsite power source is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 kV and 230 kV grid must remain stable if both DCPP units trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the DCPP operating staff for Operability determination.

SPECIFIC REQUIREMENTS

Note: This section identifies the operational requirements for the DCPP offsite power supply. These requirements are part of the DCPP design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised as necessary. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPP unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to the ISO, PG&E and the DCPP operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements requires prior approval by PG&E.

1. Three transmission lines into the 500 kV DCPP switchyard and two lines into the 230 kV DCPP switchyard are normally in service. Any change that alters the performance capabilities of either offsite source at the applicable switchyard requires prior approval by PG&E (DCPP) and the ISO.

   No line may be removed from service at anytime without prior notification to the DCPP Operations Department. At least two independent sources of power, the 500 kV and the 230 kV systems, between the transmission network (grid) and DCPP switchyards shall be available at all times. PG&E System Operating Procedure, O-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.

2. With both Diablo Canyon units off-line, the DCPP 500 kV and 230 kV offsite power source should be capable of providing 130 MVA (i.e. dual unit orderly shutdown) to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.

3. The minimum grid voltage at DCPP 230 kV switchyard shall be maintained at or above 230 kV for normal operation with all Los Padres 230 kV elements (See list below) in service. In the event of a system disturbance or line outage that can cause the DCPP voltage to dip below 230 kV, including the trip of a DCPP unit, the grid voltage shall recover to 207 kV or above within 16 seconds.

<u>Los Padres Area Major 230 kV Elements</u>	<u>Major 500 kV Elements</u>
DCPP – Mesa Line	DCPP-Gates Line
Morro Bay – Mesa Line	DCPP-Midway Line #1 & #2 Line
Morro May – DCPP Line	
Morro Bay – Templeton Line	
Morro Bay - Midway Line #1 or #2 Line	
Morro Bay - Gates Line #2 Line	
Largest Los Padres area generator other than DCPP	
DCPP 230 kV capacitor banks	
Mesa 115 kV capacitor banks	

4. Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:

   a) The loss of two DCPP units.

   b) The loss of any generating unit on the PG&E grid.

c) The loss of any major transmission circuit or intertie on the PG&E grid.

d) The loss of any large load or block of load on the PG&E grid.

5. The maximum grid voltage at the DCPP 230 kV and 500 kV switchyards shall be maintained at or below 240 kV and 545 kV, respectively, unless required to preserve transmission network integrity.

6. The 500 kV system shall be maintained between 525 kV and 545 kV. Operation of DCPP is limited between 24.375 kV and 26.25 kV (i.e. 0.975 p.u. and 1.05 p.u.).

PG&E, in coordination with the ISO, shall perform and update system studies based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the DCPP offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition that renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPP operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPP switchyard voltages or otherwise unanalyzed render the offsite power supply Inoperable. DCPP operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO.

System studies shall consider the interconnections between PG&E, and other utilities in the Western Electricity Coordinating Council (WECC) region.

7. In the event of a complete loss of the DCPP offsite power supply (i.e. both the 230 kV and 500 kV grid interfaces) both the ISO and PG&E shall establish the following restoration priorities:

a) Highest possible priority shall be given to restoring power to the DCPP switchyards.

b) Should incoming lines to the DCPP switchyards be damaged, highest priority shall be assigned to repair and restoration of at least one line into the DCPP switchyards.

c) Repair crews engaging in power restoration activities for DCPP shall be given the highest priority for manpower, equipment, and materials.

d) Formal programs and procedures shall be in place to effect items a), b), and c) above.

8. Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:

   a) At 59.65 Hz, E19 & E20 interruptible customers are tripped.

   b) PG&E complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

9. Patrol and inspection of PG&E transmission lines shall be performed in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice.

10. Line insulators between the plant and switchyard shall be washed by PG&E on an appropriate wash cycle during the wash season in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice to reduce line outages that may result from flashovers due to possible accumulated contamination.

11. Maintenance, testing and calibration of DCPP switchyard equipment and protective relays shall be performed in accordance with the current CAISO approved PG&E Electrical Station Maintenance Practice.

12. PG&E (DCPP) maintains a safety analysis for DCPP (Section 8.0, Electric Power of DCPP 1&2 Final Safety Analysis Update Report (FSAR)). PG&E (DCPP) is required by 10CFR50.71(e) to submit to the NRC periodic updates to the FSAR. The requirements contained in this Appendix E are documented in the FSAR. Any changes to these requirements, or the Bulk Power Transmission System Reliability criteria used as a basis for compliance with a requirement, shall be transmitted by both the ISO and PG&E (Transmission operator) to PG&E (DCPP) for prior approval.

These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised September 2, 2002

OVERVIEW

The preferred source of electrical power for SONGS electrical loads (safety-related and nonsafety-related) is the ***offsite power supply*** or 230 kV grid. The offsite power supply is sometimes referred to as the ***preferred power supply*** in the regulatory documents.

The basic requirement for the offsite power supply is that it provides ***sufficient capacity and capability*** to safely shut down the reactor and to mitigate certain specified accident scenarios. When this condition is met, the offsite power supply is considered Operable with respect to the SONGS Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable to safely shutdown the units or to supply emergency electrical loads.

In specific terms, the offsite power supply voltage (at the SONGS switchyard) must stay within the range of 218 kV to 238 kV under all normal and plant accident (i.e. emergency shutdown or trip) conditions. Otherwise the offsite power supply is considered Inoperable. Since accident scenarios for which the plant is designed can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a SONGS unit (i.e., the unit breakers open), the SONGS switchyard voltage must recover to and be maintained at or above 218 kV within 2.5 seconds following the trip. If this condition cannot be met, then the offsite power supply is considered Inoperable, and action must be taken to shut down the operating SONGS unit(s). Even though these requirements apply at all times, this condition is primarily of concern when one SONGS unit is online and the other unit offline. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room for Operability determination.

The SONGS switchyard is made up of the SCE switchyard and the SDG&E switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

SPECIFIC REQUIREMENTS

Note 1: This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to SCE and the SONGS Control Room for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by SCE.

Note 2: Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.

1. Nine transmission lines into the SONGS switchyard are normally in service. Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval of SCE. (Reference 7)

   No line may be removed from service for greater than 30 days without prior notification to SCE. At least two independent transmission lines (one from SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8)

2. With both San Onofre units off-line, the SONGS offsite power source shall be capable of providing 158 MW and 96 MVAR to San Onofre for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions. (References 9, 10)

3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV. In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall recover to 218 kV or above within 2.5 seconds. (References 9, 10, 12, 13, 18)

4. The following initiating events shall not result in the loss of grid stability or availability:

   a. The loss of a San Onofre Unit (with the other unit already offline), or

   b. The loss of any generating unit on the SCE and SDG&E grids, or

   c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or

   d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids.

   (References 2, 3, 4, 8)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 238 kV. (References 10, 11, 18)

6. The normal operating voltage of the SONGS switchyard shall be maintained at 230 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18)

7. The limiting conditions for SONGS offsite power source operability are defined as follows:

   1. One SONGS unit is off- line, and
   2. One of the critical line (s) outages occurs (see list of the lines below), and
   3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the referenced nomograms in the GCC Operating Procedure : SONGS Voltage (Current revision).

   Based on these nomograms and SONGS offline unit's status, if the Grid Control Center or ISO determines that the operating point is outside the applicable derated nomogram line, they shall notify SONGS immediately that a particular transmission line is out of service, and the critical system conditions are sufficient to cause SONGS off site power source to be considered INOPERABLE; i.e., unable to support SONGS voltage at 218 kV if the remaining unit trips. SONGS Control Room will declare the offsite source inoperable (in anticipation of losing the second SONGS unit) and will declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period will be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

List of critical transmission lines/grid conditions:

Critical Line(s) Out In SCE Territory

Palo Verde -Devers 500 kV Line
Ellis- Johanna & Ellis-Santiago 230 kV Lines
Lugo-Serrano & Mira Loma-Serrano 500 kV Lines
Lugo- Mira Loma 2&3 500 kV Lines
Two Midway - Vincent 500 kV Lines
SONGS- Serrano & SONGS - Chino 230 kV Lines

Critical Line(s) Out in SDG&E Territory

Hassayampa-N. Gila 500 kV Line
N. Gila- Imperial Valley 500 kV Line
Imperial Valley- Miguel 500 kV Line
Imperial Valley- Miguel 500 kV Line & Imperial Valley- LaRosita 230 kV Line
SONGS-San Luis Rey 230 kV Tap & SONGS - Mission 230 kV Line

Critical Grid Conditions:
SCE/SDG&E Tie Separation at SONGS:

SCE/SDG&E Tie Open, Unit 3 On-Line (Unit 2 Off-Line)
SCE/SDG&E Tie Open, Unit 2 On-Line (Unit 3 Off-Line)

Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions, such as the above cases, that could render the offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to provide electrical support to safe shutdown loads and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. The following actions are required:

a. Procedures and programs shall be in effect to ensure that the SONGS Control Room is immediately notified of such conditions.

b. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, render the offsite power supply Inoperable. The SONGS Control Room shall be immediately notified of such conditions.

c. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.

d. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to SCE.

(References 1, 2, 19, 21)

System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Electricity Coordinating Council (WECC). (Reference 7)

8. In the event of loss of the SONGS offsite power supply:

Note: SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours. The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety.

a. Highest possible priority shall be given to restoring power to the SONGS switchyard. Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. (References 15, 26, 28)

b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.

c. Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.

d. Formal programs and procedures shall be in place to effect items a, b, and c above.

(References 14, 15, 16, 17, 26, 27)

9. Grid frequency shall be maintained at 60 Hertz (nominal). A trip of one SONGS

unit shall not cause the grid frequency to dip below 59.7 Hertz. SCE and SDG&E comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

Note: System separation between SCE and SDG&E at the SONGS bus tie on low grid frequency mentioned in the previous version of the TCA is being removed from SONGS by mid-2002. Increased load shedding schemes by SDG&E have been implemented which preclude the need for system separation at SONGS bus ties on low frequency.

(References 7, 20)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report shall be maintained. It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7)

11. Patrol and inspection of SCE and SDG&E transmission lines shall be performed in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice or as required by the NRC plant-operating license, whichever requirement is more stringent. These patrols and inspections are to ensure that the physical and electrical integrity of transmission system components are maintained. (Reference 7)

12. Line insulators on lines which carry power from the plant to the grid shall be washed as required by the NRC plant-operating license or on an appropriate wash cycle in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. The purpose and frequency of which is proven to prevent line outages that may result from flashovers due to accumulated contamination. (Reference 7)

13. Maintenance, testing and calibration of SCE and SDG&E station equipment and protective relays shall be performed in accordance with the current ISO approved Electrical Station Maintenance Practice or as required by the NRC plant operating license, whichever requirement is more stringent. (Reference 7)

14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of SONGS switchyard battery chargers and DC system components shall be performed routinely. (Reference 7, 23)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS 2 & 3 Updated Final Safety Analysis Report (UFSAR) shall be provided annually. These updates will be used by SCE to prepare a UFSAR change submittal to the NRC. SONGS is required by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.

REFERENCES

1) SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems

2) 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems

3) NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System

4) NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System

5) NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems

6) NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems

7) SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power

8) ANSI/IEEE Std. 765-1983 Preferred Power Supply for Nuclear Power Generating Stations

9) SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident

10) SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation

11) SONGS Design Calculation E4C-092, Short Circuit Studies

12) SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting

13) DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems

14) 90051, SONGS Station Blackout Analyses

15) NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors

16) Letter from M. 0. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, 'Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"

17) Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"

18) System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station (Current approved revision)

19) GCC Operating Procedure: SONGS Voltage (Current approved revision)

20) System Operating Bulletin 113, San Onofre 220 kV System Separation (Current approved revision)

21) Regulatory Guide 1.93, Availability of Electric Power Sources

23) SCE Division Order 60.20, Storage Batteries (Current approved revision)

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration (Current approved revision)

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV (Current approved revision)

28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies (Current approved revision)

TRANSMISSION CONTROL AGREEMENT

APPENDIX F

NOTICES

NOTICES

California Independent System Operator

Name of Primary Representative:	Deborah A. Le Vine
Title:	Director of Contracts
Address:	151 Blue Ravine Road
City/State/Zip Code:	Folsom, California 95630
Email Address:	dlevine@caiso.com
Phone:	(916) 351-2144
Fax No:	(916) 351-2487

Name of Alternative Representative:	Randy Abernathy
Title:	Vice President of Market Services
Address:	151 Blue Ravine Road
City/State/Zip Code:	Folsom, California 95630
Email Address:	rabernathy@caiso.com
Phone:	(916) 351-4435
Fax No:	(916) 351-2350

Pacific Gas and Electric Company

Name of Primary Representative:	Rod Maslowski
Title:	Director, Electric System Operations
Address:	77 Beale Street, Room 1526
City/State/Zip Code:	San Francisco, CA 94105
Email Address:	RJM8@pge.com
Phone:	415-973-1218
Fax No:	415-973-3341

Name of Alternative Representative:	Judi Mosley
Title:	Director, Interconnection Services
Address:	77 Beale Street, Room 1355
City/State/Zip Code:	San Francisco, CA 94105
Email Address:	JKM8@PGE.COM
Phone:	415 973-4408
Fax No:	415 973-7891

San Diego Gas & Electric Company

Name of Primary Representative:	Geoff Gaebe
Title:	Director - Electrical Engineering
Address:	8316 Century Park Court
City/State/Zip Code:	San Diego, CA 92123
Email Address:	ggaebe@semprautilities.com
Phone:	858-654-1636
Fax No:	858-654-1692

Name of Alternative Representative:	Ali Yari
Title:	Manager Grid Operation Services
Address:	9060 Friars Road
City/State/Zip Code:	San Diego, CA 92108
Email Address:	yari@semprautilities.com
Phone:	619-725-8639
Fax No:	619-683-3291

Southern California Edison Company

Name of Primary Representative: Richard M. Rosenblum

Title: Senior Vice President, Transmission & Distribution

Address: 2244 Walnut Grove Ave., GO4

City/State/Zip Code: Rosemead, California 91770

Email Address: Richard.Rosenblum@SCE.com

Phone: (626) 302-2123

Fax No: (626) 302-2781

Name of Alternative Representative: John R. Fielder

Title: Senior Vice President, Regulatory Policy & Affairs

Address: 2244 Walnut Grove Ave., GO4

City/State/Zip Code: Rosemead, California 91770

Email Address: John.Fielder@SCE.com

Phone: (626) 302-3440

Fax No: (626) 302-2970

City of Vernon

Name of Primary Representative:	Bruce V. Malkenhorst
Title:	City Administrator
Address:	4305 Santa Fe Avenue
City/State/Zip Code:	Vernon, California 90058
Email Address:	bmalkenhorst@ci.vernon.ca.us
Phone:	(323) 583-8811 extension 266
Fax No:	(323) 581-7924

Name of Alternative Representative:	Kenneth J. DeDario
Title:	Director of Utilities
Address:	4305 Santa Fe Avenue
City/State/Zip Code:	Vernon, California 90058
Email Address:	kdedario@ci.vernon.ca.us
Phone:	(323) 583-8811 extension 211
Fax No:	(323) 826-1425

City of Anaheim

Name of Primary Representative:	Sheryll A. Schroeder
Title:	City Clerk
Address:	200 S. Anaheim Blvd.
City/State/Zip Code:	Anaheim, California 92805
Email Address:	sschroeder@anaheim.net
Phone:	(714) 765-5645
Fax No:	(714) 765-4105

Name of Alternative Representative:	Marcie L. Edwards
Title:	Public Utilities General Manager
Address:	201 S. Anaheim Blvd., Suite 1101
City/State/Zip Code:	Anaheim, California 92805
Email Address:	medwards@anaheim.net
Phone:	(714) 765-5173
Fax No:	(714) 765-4138

City of Azusa

Name of Primary Representative:	Joseph Hsu
Title:	Director of Utilities
Address:	729 N. Azusa Avenue
City/State/Zip Code:	Azusa, CA 91702
Email Address:	jhsu@ci.azusa.ca.us
Phone:	(626) 812-5171
Fax No:	(626) 334-3163

Name of Alternative Representative:	Bob Tang
Title:	Assistant Director of Resource Management
Address:	729 N. Azusa Avenue
City/State/Zip Code:	Azusa, CA 91702
Email Address:	btang@ci.azusa.ca.us
Phone:	(626) 812-5214
Fax No:	(626) 334-3163

City of Banning

Name of Primary Representative:	Paul Toor
Title:	Public Works Director
Address:	99 East Ramsey Street
City/State/Zip Code:	Banning, California 92220
Email Address:	ptoor@ci.banning.ca.us
Phone:	(909) 922-3130
Fax No:	(909) 922-3141

Name of Alternative Representative:	Fred Mason
Title:	Power Resource Specialist
Address:	176 East Lincoln Street
City/State/Zip Code:	Banning, California 92220
Email Address:	fmason@ci.banning.ca.us
Phone:	(909) 922-3265
Fax No:	(909) 849-1550

City of Riverside

Name of Primary Representative:	Thomas P. Evans
Title:	Public Utilities Director
Address:	3900 Main Street
City/State/Zip Code:	Riverside, CA 92522
Email Address:	tevans@ci.riverside.ca.us
Phone:	(909) 826-5502
Fax No:	(909) 369-0548

Name of Alternative Representative:	Gary L. Nolff
Title:	Power Contracts/Projects Manager
Address:	2911 Adams Street
City/State/Zip Code:	Riverside, CA 92504
Email Address:	gnolff@pac.state.ca.us
Phone:	(909) 351-6313
Fax No:	(909) 351-6328

ATTACHMENT B

TRANSMISSION CONTROL AGREEMENT

Among
The Independent System Operator
and
Transmission Owners

TABLE OF CONTENTS

TRANSMISSION CONTROL AGREEMENT
Among
The Independent System Operator
and
Transmission Owners

The Parties to this Transmission Control Agreement ("Agreement") first dated as of ______________________________, _________, are

(1) The California Independent System Operator Corporation, a California nonprofit public benefit Corporation (the "Independent System Operator" or "ISO" which expression includes its permitted successors); and

(2) Entities owning or holding Entitlements to transmission lines and associated facilities who subscribe to this Agreement ("Transmission Owners" or "TOs", which expression includes their permitted successors and assigns).

This Agreement is made with reference to the following facts:

(i) The Legislature of the State of California enacted Assembly Bill 1890 ("AB 1890") that addressed the restructuring of the California electric industry in order to increase competition in the provision of electricity.

(ii) AB 1890 provides the means for transforming the regulatory framework of California's electric industry in ways to meet the objectives of the law.

(iii) In order to create a new market structure, AB 1890 establishes an Independent System Operator ("ISO") with centralized control of a state-wide transmission grid charged with ensuring the efficient use and reliable operation of the transmission system.

(iv) AB 1890 states that it is the intention of the California Legislature that California transmission owners commit control of their transmission facilities to the ISO with the assurances provided in the law that the financial interests of such TOs will be protected.

(v) Each TO: (1) owns, operates, and maintains transmission lines and associated facilities; and/or (2) has Entitlements to use certain transmission lines and associated facilities, with responsibilities attached thereto.

(vi) Each TO, upon satisfying the criteria for becoming a Participating TO under Section 2.2 of this Agreement, will transfer to the ISO Operational Control of certain transmission lines and associated facilities which are to be incorporated by the ISO into the ISO Controlled Grid for the purpose of allowing them to be controlled as part of an integrated Control Area.

(vii) Each Participating TO will continue to own and maintain its transmission lines and associated facilities, if any, and will retain its Entitlements, if any, and associated responsibilities.

(viii) The ISO intends to provide to each Participating TO access to the ISO Controlled Grid while exercising its Operational Control for the benefit of all Market Participants by providing non-discriminatory transmission access, Congestion Management, grid security, and Control Area services.

(ix) Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("Edison") (each a Participating TO) are entering into this agreement transferring Operational Control of their transmission facilities in reliance upon California Public Utilities Code Sections

367, 368, 375, 376 and 379 enacted as part of AB 1890 which contain assurances and schedules with respect to recovery of transition costs.

(x) The Parties desire to enter into this Agreement in order to establish the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities.

In consideration of the above and the covenants and mutual agreements set forth herein, and intending to be legally bound, the Parties agree as follows:

1. DEFINITIONS

Capitalized terms in this Agreement have the meaning set out in the Master Definitions Supplement set out in Appendix D. No subsequent amendment to the Master Definitions Supplement shall affect the interpretation of this Agreement unless made pursuant to Section 26.11.

2. PARTICIPATION IN THIS AGREEMENT

2.1. Transmission Owners:

2.1.1 Initial Transmission Owners.

The following entities are subscribing to this Agreement as of the date hereof for the purpose of applying to become Participating TOs in accordance with Section 2.2:

i. Pacific Gas and Electric Company;

ii. San Diego Gas & Electric Company; and

iii. Southern California Edison Company.

2.1.2 **Right to Become a Party.**

After this Agreement takes effect, any other owner of or holder of Entitlements to transmission lines and facilities connected to the ISO Controlled Grid may apply to the ISO under Section 2.2 to become a Participating TO and become a Party to this Agreement.

2.2. Applications for Participating TO Status; Eligibility Criteria.

2.2.1 **Application Procedures.** All applications under this Section 2.2 shall be made in accordance with the procedures adopted by the ISO from time to time and shall be accompanied by:

(i) a description of the transmission lines and associated facilities that the applicant intends to place under the ISO's Operational Control;

(ii) in relation to any such transmission lines and associated facilities that the applicant does not own, a copy of each document setting out the applicant's Entitlements to such lines and facilities;

(iii) a statement of any Encumbrances to which any of the transmission lines and associated facilities to be placed under the ISO's Operational Control are subject, together with any documents creating such Encumbrances and any dispatch protocols to give effect to them, as the ISO may require;

(iv) a statement that the applicant intends to place under the ISO's Operational Control all of the transmission lines and associated facilities referred to in Section 4.1 that it owns or, subject to the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff, to which it has Entitlements and its reasons for believing that certain lines and facilities do not form part of the applicant's transmission network pursuant to Sections 4.1.1.i and 4.1.1.ii;

(v) a statement of any Local Reliability Criteria to be included as part of the Applicable Reliability Criteria;

(vi) a description of the applicant's current maintenance practices;

(vii) a list of any temporary waivers that the applicant wishes the ISO to grant under Section 5.1.6 and the period for which it requires them;

(viii) a copy of the applicant's proposed TO Tariff, if any, must be filed;

(ix) address and contact names to which notices under this Agreement may be sent pursuant to Section 26.1;

(x) any other information that the ISO may reasonably require in order to evaluate the applicant's ability to comply with its obligations as a Participating TO; and

(xi) details of the applicant's Settlement Account.

2.2.2 **Notice of Application.** The ISO shall require the applicant to deliver to each existing Participating TO a copy of each application under this Section 2.2 and each amendment, together with all supporting documentation and to provide the public with reasonable details of its application and each amendment through WEnet or the ISO internet website. The ISO shall not grant an application for Participating TO status until it has given each other Party and the public sixty (60) days to comment on the original application and thirty (30) days to comment on each amendment.

2.2.3 **Determination of Eligibility.** Subject to Section 2.2.4, the ISO shall permit a Party who has submitted an application under this Section 2.2 to become a Participating TO if, after considering all comments received from other Parties and third parties, the ISO determines that:

i. the applicant's transmission lines and associated facilities that are to be placed under the ISO's Operational Control can be incorporated into the ISO Controlled Grid without any material adverse impact on its reliability;

ii. incorporating such transmission lines and associated facilities into the ISO Controlled Grid will not put the ISO in breach of Applicable Reliability Criteria and its obligations as a member of WSCC;

iii. objections by the ISO under Section 4.1.3 shall have been withdrawn or determined by the ISO Governing Board to be invalid;

iv. all applicable regulatory approvals of the applicant's TO Tariff have been obtained; and

v. the applicant is capable of performing its obligations under this Agreement.

Objections under Section 4.1.3 relating solely to a portion of a TO's Facilities shall not prevent the TO from becoming a Participating TO while the objections are being resolved.

2.2.4 **Challenges to Eligibility.** The ISO shall permit a Party to become a Participating TO pending the outcome of ISO ADR Procedures challenging whether or not the applicant satisfies the criteria set out in Section 2.2.3 if the ISO determines that the applicant satisfies those criteria unless otherwise ordered by FERC.

2.2.5 **Becoming a Participating TO.** A Party whose application under this Section 2.2 has been accepted shall become a Participating TO with effect from the date when its TO Tariff takes effect, either as a result of acceptance by FERC or by action of a Local Regulatory Authority, whichever is appropriate. The TO Tariff of each Participating TO shall be posted on WEnet or the ISO internet website.

2.2.6 **Procedures and Charges.** The ISO shall adopt fair and non-discriminatory procedures for processing applications under this Section 2.2. The ISO shall publish its procedures for processing applications under this Section 2.2 on WEnet or on the ISO internet website and shall furnish a copy of such procedures to FERC. Applicants shall pay all costs incurred by the ISO in processing their applications. The ISO will furnish applicants, upon request, an itemized bill for the costs of processing their application.

2.3. Tax Exempt Debt.

2.3.1 **Municipal Tax-Exempt TOs.** In the event a Municipal Tax-Exempt TO executes this Agreement in reliance upon this Section 2.3, it shall provide written notice thereof to the ISO. Notwithstanding any other provision to the contrary herein, except for this Section 2.3, no other provisions of this Agreement shall become effective with respect to a Municipal Tax-Exempt TO until such Municipal Tax-Exempt TO's nationally recognized bond counsel renders an opinion, generally of the type regarded as unqualified in the bond market, that participation in the ISO Controlled Grid in accordance with this Agreement will not adversely affect the tax-exempt status of any Municipal Tax-Exempt Debt issued by, or for the benefit of, the Municipal Tax-Exempt TO. A Municipal Tax-Exempt TO shall promptly seek, in good faith, to obtain such unqualified opinion from its bond counsel at the earliest opportunity. Upon receipt of such unqualified opinion, a Municipal Tax-Exempt TO shall provide a copy of the opinion to the ISO and all other provisions of this Agreement shall become effective with respect to such Municipal Tax-Exempt TO as of the date thereof. If the Municipal Tax-Exempt TO is unable to provide to the ISO such unqualified opinion within one year of the execution of this Agreement by the Municipal Tax-Exempt TO, without further act, deed or notice this Agreement shall be deemed to be void *ab initio* with respect to such Municipal Tax-Exempt TO.

2.3.2 **Acceptable Encumbrances.** A Transmission Owner that has issued Local Furnishing Bonds may become a Participating TO under Section 2.2 even though covenants or restrictions applicable to the Transmission Owner's Local Furnishing Bonds require the ISO's Operational Control to be exercised subject to Encumbrances, provided that such Encumbrances do not materially impair the ISO's ability to meet its obligations under the ISO Tariff or the Transmission Owner's ability to comply with the TO Tariff.

2.3.3 **Savings Clause.** Nothing in this Agreement shall compel any Participating TO or Municipal Tax-Exempt TO which has issued Tax-Exempt Debt to violate restrictions applicable to transmission facilities financed with Tax-Exempt Debt or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995.

3. EFFECTIVE DATE, TERM AND WITHDRAWAL

3.1. Effective Date.

This Agreement shall become effective as of the latest of:

i. the date that it is signed by the ISO and the Transmission Owners referred to in Section 2.1.1;

ii. the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decision 97-12-131; and

iii. the date when this Agreement is accepted for filing and made effective by the FERC.

3.2. Term.

This Agreement shall remain in full force and effect until terminated: (1) by operation of law or (2) the withdrawal of all Participating TOs pursuant to Section 3.3 or Section 4.4.1.

3.3. Withdrawal.

3.3.1 **Notice.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement on two years' prior written notice to the other Parties.

3.3.2 **Sale.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement if that Participating TO sells or otherwise disposes of all of the transmission facilities and Entitlements that the Participating TO placed under the ISO's Operational Control, subject to the requirements of Section 4.4.

3.3.3 **Conditions of Withdrawal.** Any withdrawal from this Agreement pursuant to Section 3.3.1 or Section 3.3.2 shall be contingent upon the withdrawing party obtaining any necessary regulatory approvals for such withdrawal. The withdrawing Participating TO shall make a good faith effort to ensure that its withdrawal does not unduly impair the ISO's ability to meet its Operational Control responsibilities as to the facilities remaining within the ISO Controlled Grid.

3.3.4 **Publication of Withdrawal Notices.** The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.3.

3.4 Withdrawal Due to Adverse Tax Action.

3.4.1 **Right to Withdraw Due To Adverse Tax Action.** Subject to Sections 3.4.2 through 3.4.4, in the event an Adverse Tax Action Determination identifies an Impending Adverse Tax Action or an Actual Adverse Tax Action, a Tax Exempt Participating TO may exercise its right to Withdraw for Tax Reasons. The right to Withdraw for Tax Reasons, in accordance with the provisions of this Section 3.4, shall not be subject to any approval by the ISO, the FERC or any other Party.

3.4.2 **Adverse Tax Action Determination.**

3.4.2.1 A Tax Exempt Participating TO shall provide to all other Parties written notice of an Adverse Tax Action Determination and a copy of the Tax Exempt Participating TO's (or its joint action agency's) nationally recognized bond counsel's opinion or an IRS determination supporting such Adverse Tax Action Determination. Such written notice shall be provided promptly under the circumstances, but in no event more than 15 working days from the date of receipt of such documents.

3.4.2.2 The Adverse Tax Action Determination shall include (i) the actual or projected date of the Actual Adverse Tax Action and (ii) a description of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the Tax Exempt Debt that is the subject of such Adverse Tax Action Determination. A Tax Exempt Participating TO shall promptly notify all other Parties in writing in the event the actual or projected date of the Actual Adverse Tax Action changes. The Tax Exempt Participating TO's determination of the actual or projected date of the Actual Adverse Tax Action shall be binding upon all Parties.

3.4.2.3 Any transmission lines, associated facilities or Entitlements of the Tax Exempt Participating TO not identified in both the Adverse Tax Action Determination and the written notice of Withdrawal for Tax Reasons shall remain under the ISO's Operational Control.

3.4.3 **Withdrawal Due to Impending Adverse Tax Action.** A Tax Exempt Participating TO may Withdraw for Tax Reasons prior to an Actual Adverse Tax Action if such Tax Exempt Participating TO provides prior written notice of its Withdrawal for Tax Reasons to all other Parties as required in Sections 3.4.3(i) through 3.4.3(iv).

i. In the event the date of the Adverse Tax Action Determination is seven months or more from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least six months in advance of the projected date of the Actual Adverse Tax Action.

ii. In the event the date of the Adverse Tax Action Determination is less than seven months but more than two months from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax

Reasons to all other Parties at least 30 days in advance of the projected date of the Actual Adverse Tax Action.

iii. In the event the date of the Adverse Tax Action Determination is between two months and one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least 15 days in advance of the projected date of the Actual Adverse Tax Action.

iv. In the event the date of the Adverse Tax Action Determination is less than one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO shall have up to 15 days following the date of the Adverse Tax Action Determination to exercise its right to Withdraw for Tax Reasons, and if so exercised shall provide no later than one day thereafter written notice of its Withdrawal for Tax Reasons to all other Parties.

v. With respect to Sections 3.4.3(i) through 3.4.3(iii), upon receipt by the ISO of a notice to Withdraw for Tax Reasons, the ISO shall promptly begin working with the applicable Tax Exempt Participating TO to relinquish the ISO's Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, provided that such Operational Control must be relinquished by the ISO no later than five days prior to the projected date of the Actual Adverse Tax Action. With respect to Section 3.4.3(iv), (1) if the notice of Withdrawal for Tax Reasons is received by the ISO at least six days prior to the projected date of the Actual Adverse Tax Action, Operational Control over the affected transmission lines, associated facilities or Entitlements must be relinquished by the ISO to such Tax Exempt Participating TO no later than five days prior to the projected date of the Actual Adverse Tax Action, or (2) if the notice of Withdrawal for Tax Reasons is received by the ISO any time after six days prior to the projected date of the Actual Adverse Tax Action, the ISO shall on the next day relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.4 **Withdrawal Due to Actual Adverse Tax Action.** In addition to the foregoing, upon the occurrence of an Actual Adverse Tax Action, the affected Tax Exempt Participating TO may immediately Withdraw for Tax Reasons. The Tax Exempt Participating TO shall have up to 15 days from the date of the Adverse Tax Action Determination with respect to an Actual Adverse Tax Action to exercise its right to Withdraw for Tax Reasons. If the Tax Exempt Participating TO determines to exercise its right to Withdraw for Tax Reasons, upon receipt of the notice of Withdrawal for Tax Reasons, the ISO shall immediately relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.5 **Alternate Date To Relinquish Operational Control.** Notwithstanding anything to the contrary in this Section 3.4, the ISO and a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons may mutually agree in writing to an alternate date that the ISO shall relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO. If the ISO or a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons desires an alternate date from the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, such party promptly shall give written notice to the other, and each agrees to negotiate in good faith, for a reasonable period of time, to determine whether or not they can reach mutual agreement for such an alternate date; provided, however, such good faith negotiations are not required to be conducted during the five days preceding the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements.

3.4.6 **Procedures to Relinquish Operational Control.** The ISO shall implement a procedure jointly developed by all Parties to relinquish Operational Control over the affected transmission lines, associated facilities, or Entitlements as provided in this Section 3.4.

3.4.7 **Right to Rescind Notice of Withdrawal for Tax Reasons.** At any time up to two days prior to the ISO's relinquishment to the Tax Exempt Participating TO of Operational Control over the affected transmission lines, associated facilities or Entitlements, a Tax Exempt Participating TO may rescind its notice of Withdrawal for Tax Reasons by providing written notice thereof to all other Parties, and such notice shall be effective upon receipt by the ISO.

3.4.8 **Amendment of Agreement.** Following the relinquishment by the ISO of Operational Control in accordance with this Section 3.4, the ISO promptly shall prepare the necessary changes to this Agreement, submit the changes to the

Participating TOs for execution and take whatever regulatory action, if any, that is required to properly reflect the Withdrawal for Tax Reasons.

3.4.9 **Provision of Information by ISO.** To assist Tax Exempt Participating TOs in identifying at the earliest opportunity Impending Adverse Tax Actions or Actual Adverse Tax Actions, the ISO promptly shall provide to Participating TOs any non-confidential information regarding any ISO plans, actions or operating protocols that the ISO believes might adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO.

3.4.10 **Publication of Notices.** The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.4.

4. TRANSFER OF OPERATIONAL CONTROL

4.1. TO Facilities and Rights Provided to the ISO.

4.1.1 **ISO Controlled Grid**. Subject to Section 4.1.2 and the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff and subject to the applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements, each Participating TO shall place under the ISO's Operational Control the transmission lines and associated facilities forming part of the transmission network that it owns or to which it has Entitlements. The Initial Transmission Owners identified in Section 2.1.1 shall be deemed to have placed such transmission lines and associated facilities under the ISO's Operational Control as of the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decisions 97-12-131 and 98-01-053. Any transmission lines or associated facilities that the ISO determines not to be necessary to fulfill the ISO's responsibilities under the ISO Tariff in accordance with Section 4.1.3 of this Agreement shall not be treated as part of a Participating TO's network for the purposes of this Section 4.1. The ISO shall recognize the rights and obligations of owners of jointly-owned facilities which are placed under the ISO's Operational Control by one or more but not all of the joint owners. The ISO shall, in exercise of eOperational eControl transferred to it, ensure that the operating obligations, as specified by the Participating TO pursuant to Section 6.4.2 of this Agreement, for the contracts referenced in Appendix B are performed. Any other terms of such contracts shall not be the responsibility of the ISO. The following transmission lines and associated facilities are also deemed not to form part of a Participating TO's transmission network:

i. directly assignable radial lines and associated facilities interconnecting generation (other than those facilities which may be identified from time to time interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support) and

ii. lines and associated facilities classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test and other facilities excluded consistent with FERC established criteria for determining facilities subject to ISO Operational Control.

4.1.2 **Transfer of Facilities by Local Furnishing Participating TOs.** This Section 4.1.2 is applicable only to the enlargement of transmission capacity by Local Furnishing Participating TOs. The ISO shall not require a Local Furnishing Participating TO to enlarge its transmission capacity except pursuant to an order under

Section 211 of the FPA directing the Local Furnishing Participating TO to enlarge its transmission capacity as necessary to provide transmission service as determined pursuant to Section 3.2.9 of the ISO Tariff. If an application under Section 211 of the FPA is filed by an eligible entity (or the ISO acting as its agent), the Local Furnishing Participating TO shall thereafter, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 212(c) of the FPA. Upon receipt of a final order from FERC under Section 211 of the FPA that is no longer subject to rehearing or appeal, such Local Furnishing Participating TO shall enlarge its transmission capacity to comply with that FERC order and shall transfer to the ISO Operational Control over its expanded transmission facilities in accordance with this Section 4.

4.1.3 **Refusal of Facilities.** The ISO may refuse to exercise Operational Control over certain of an applicant's transmission lines, associated facilities or Entitlements if it determines during the processing of an application under Section 2.2 that any one or more of the following conditions exist:

i. The transmission lines, associated facilities or Entitlements do not meet or do not permit the ISO to meet the Applicable Reliability Criteria and the applicant fails to give the ISO a written undertaking to take all good faith actions necessary to ensure that those transmission lines, facilities or Entitlements, as the case may be, meet the Applicable Reliability Criteria within a reasonable period from the date of the applicant's application under Section 2.2 as determined by the ISO.

ii. The transmission lines, associated facilities or Entitlements are subject to Encumbrances that unduly impair the ISO's ability to exercise its Operational Control over them in accordance with the ISO Tariff and the applicant fails to give the ISO a written undertaking to negotiate in good faith to the extent permitted by the applicable contract the removal of the Encumbrances identified by the ISO which preclude it from using unused capacity on the relevant transmission lines. If the applicant provides such written undertaking but is unable to negotiate the removal of such Encumbrances to the extent required by the ISO, the ADR Procedure shall be used to resolve any disputes between the ISO and the applicant. For this purpose, Non-Participating TOs may utilize ISO ADR procedures on a voluntary basis.

iii. The transmission lines, associated facilities and Entitlements are located in a Control Area outside of California, are operated under the direction of another Control Area or independent system operator, and cannot be integrated into the ISO Controlled Grid due to technical considerations.

If the ISO refuses to accept any of an applicant's transmission lines, facilities or Entitlements, then that applicant shall have the right to notify the ISO within a reasonable period from being notified of such refusal that it will not proceed with its application under Section 2.2.

4.1.4 **Facilities Initially Placed Under the ISO's Operational Control.** The transmission lines, associated facilities and Entitlements which each Participating TO places under the ISO's Operational Control on the date that this Agreement takes effect with respect to it shall be identified in Appendix A.

4.1.5 **Warranties.** Each Participating TO warrants that as of the date on which it becomes a Participating TO pursuant to Section 2.2.5:

i. the transmission lines and associated facilities that it is placing under the ISO's Operational Control and the Entitlements that it is making available for the ISO's use are correctly identified in Appendix A (as amended in accordance with this Agreement); that the Participating TO has all of the necessary rights and authority to place such transmission lines and associated facilities under the ISO's Operational Control subject to the terms and conditions of all agreements governing the use of such transmission lines and associated facilities; and that the Participating TO has the necessary rights and authority to transfer the use of such Entitlements to the ISO subject to the terms and conditions of all agreements governing the use of such Entitlements;

ii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control are not subject to any Encumbrances except as disclosed in Appendix B (as amended in accordance with this Agreement);

iii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control meet the Applicable Reliability Criteria (ARC) for the relevant Participating TO except as disclosed in writing to the ISO. As to the Local Reliability Criteria component of ARC, each Participating TO has provided the ISO with such information required to identify such Participating TO's Local Reliability Criteria.

4.2. The ISO Register.

4.2.1 **Register of Facilities Subject to ISO Operational Control.** The ISO shall maintain a register (the "ISO Register") of all transmission lines, associated facilities and Entitlements that are for the time being subject to the ISO's Operational Control. The ISO Register shall also indicate those facilities over which the ISO has asserted temporary control pursuant to Section 4.5.2 and whether or not the ISO has commenced proceedings under Section 203 of the FPA in relation to them.

4.2.2 **Contents.** The ISO Register shall disclose in relation to each transmission line and associated facility subject to the ISO's Operational Control:

i. the identity of the Participating TO responsible for its operation and maintenance and its owner(s) (if other than the Participating TO);

ii. the date on which the ISO assumed Operational Control over it and, in the case of transmission lines and associated facilities over which it has asserted temporary Operational Control, the date on which it relinquished Operational Control over it;

iii. the date of any change in the identity of the Participating TO responsible for its operation and maintenance or in the identity of its owner; and

iv. its applicable ratings.

4.2.3 **Updates.** In order to keep ~~T~~the ISO Register current, each Participating TO shall submit an ISO Register change for ~~shall be updated by the end of the next business day to reflect~~ each addition or removal of a transmission line or associated facility or ~~e~~Entitlement from the ISO's Operational Control or any change in a transmission line or associated facility's ownership, rating or the identity of the responsible Participating TO. The ISO shall review each ISO Register change for accuracy and to assure that all requirements of this Agreement have been met. If the ISO determines that a submitted ISO Register change is accurate and meets all the requirements of this Agreement, the ISO will modify the ISO Register to incorporate such change by the end of the next Business Day. The ISO may determine that an ISO

Register change cannot be implemented due to (a) lack of clarity or necessary information, or (b) conflict between the revised rating and applicable contractual, regulatory or legal requirements including operating considerations, or other conflict with the terms of this Agreement. In such event, the ISO promptly will communicate to the Participating TO the reason that the ISO cannot implement the ISO Register change and will work with the Participating TO in an attempt to resolve promptly the concerns leading to the ISO's refusal to implement an ISO Register change. The ISO consent required with respect to a sale, assignment, release, transfer or other disposition of transmission lines, associated facilities or Entitlements as provided in Section 4.4 hereof shall not be withheld by the ISO as a result of an ISO determination that an ISO Register change cannot be implemented pursuant to this Section 4.2.3.

4.2.4 **Publication.** The ISO shall make the ISO Register available to the ~~public~~ Participating TOs on WEnet or ~~the~~ a secure ISO-maintained internet website.

4.2.5 **Duty to Maintain Records.** The ISO shall maintain the ISO Register in a form that conveniently shows the entities responsible for operating, maintaining and controlling the transmission lines and associated facilities forming part of the ISO Controlled Grid at any time and the periods during which they were so responsible.

4.3. Rights and Responsibilities of Participating TOs.

Each Participating TO shall retain its benefits of ownership and its rights and responsibilities in relation to the transmission lines and associated facilities placed under the ISO's Operational Control except as otherwise provided in this Agreement. Participating TOs shall be responsible for operating and maintaining those lines and facilities in accordance with this Agreement, the Applicable Reliability Criteria, the Operating Procedures and other criteria, ISO Protocols, procedures and directions of the ISO issued or given in accordance with this Agreement. Rights and responsibilities that have not been transferred to the ISO as operating obligations under Section 4.1.1 of this Agreement remain with the Participating TO. This Agreement shall have no effect on the remedies for breach or non-performance available to parties to existing interconnection, integration, exchange, operating joint ownership and joint participation agreements.

4.4. Sale or Disposal of Transmission Facilities or Entitlements.

4.4.1 **Sale or Disposition.**

4.4.1.1 No Participating TO shall sell or otherwise dispose of any lines or associated facilities forming part of the ISO Controlled Grid without the ISO's prior written consent, which consent shall not be unreasonably withheld.

4.4.1.2 As a condition to the sale or other disposition of any lines or associated facilities forming part of the ISO Controlled Grid to an entity that is not a Participating TO, the Participating TO shall require the transferee to assume in writing all of the Participating TO's obligations under this Agreement (but without necessarily requiring it to become a Participating TO for the purposes of the ISO Tariff or a TO Tariff).

4.4.1.3 Any subsequent sale or other disposition by a transferee referred to in Section 4.4.1.2 shall be subject to this Section 4.4.1.

4.4.1.4 A transferee referred to in Section 4.4.1.2 that does not become a Participating TO shall have the same rights and responsibilities regarding withdrawal that a Participating TO has under Sections 3.3.1 and 3.3.3.

4.4.2 **Entitlements.** No Participating TO shall sell, assign, release, or transfer any Entitlements that have been placed under the ISO's Operational Control without the ISO's prior written consent, which consent shall not be unreasonably withheld, provided that such written consent is not required for such release or transfer to another Participating TO who is not in any material respect in breach of its obligations under this Agreement and who has not given notice of its intention to withdraw from this Agreement.

4.4.3 **Encumbrances.** No Participating TO 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. The ISO shall give its consent to the creation or extension of an Encumbrance within thirty (30) days after receiving a written request for its consent disclosing in reasonable detail the nature of and reasons for the proposed change unless the ISO reasonably determines that the change is inconsistent with the Participating TO's obligations under the ISO Tariff or the TO Tariff or that the change may materially impair the ISO's ability to exercise Operational Control over the relevant lines or facilities or may reduce the reliability of the ISO Controlled Grid. Exercise of rights under an Existing Contract shall not be deemed to create a new Encumbrance for the purposes of this Section 4.4.3.

4.5. Procedure for Designating ISO Controlled Grid Facilities.

4.5.1 **Additional Facilities.** If the ISO determines that it requires

Operational Control over additional transmission lines and associated facilities not then constituting part of the ISO Controlled Grid in order to fulfill its responsibilities in relation to the ISO Controlled Grid then the ISO shall apply to FERC pursuant to Section 203 of the Federal Power Act, and shall make all other regulatory filings necessary to obtain approval for such change of control and shall serve a copy of all such applications on the affected Participating TO and the owner of such lines and facilities (if other than the Participating TO). In the event that a Party invokes the dispute resolution provisions identified in Section 15 with respect to the transfer of Operational Control over a facility, such facility shall not be transferred while the dispute resolution process is pending except pursuant to Section 4.5.2.

4.5.2 **Temporary Operational Control.** The ISO may exercise temporary Operational Control over any transmission lines or associated facilities of a Participating TO (including lines and facilities to which the Participating TO has sufficient Entitlement to permit the ISO to exercise Operational Control over them) that do not then form part of the ISO Controlled Grid:

i. in order to prevent or remedy an imminent System Emergency;

ii. on reasonable notice, for a period not exceeding ninety (90) days, in order to determine whether exercising Operational Control over the relevant lines and facilities will assist the ISO to meet Applicable Reliability Criteria or to fulfill its Control Area responsibilities under the ISO Tariff; or

iii. subject to any contrary order of FERC, pending the resolution of the procedures referenced in Section 4.5.1.

4.5.3 **Return of Control of Facilities.** Control of facilities over which the ISO has assumed temporary oOperational cControl will be returned to the appropriate Participating TO when the conditions set forth in Section 4.5.2 no longer require the ISO to assume such temporary control.

4.5.4 **Transmission Expansion Projects.** Any transmission expansion projects carried out pursuant to Section 3.2 of the ISO Tariff shall be subject to the ISO's Operational Control from the date that it goes into service or after such period as the ISO deems to be reasonably necessary for the ISO to integrate the project into the ISO Controlled Grid.

4.6. TOs Control Centers.

4.6.1 **ISO's Right to Occupy Participating TOs Control Centers.** From the ISO Operations Date until the date when, in the reasonable opinion of the ISO, the ISO Control Center is established in accordance with Section 2.3.1.1 of the ISO Tariff, each Participating TO shall allow the ISO access to and such rights to occupy the Participating TO's existing control centers as the ISO reasonably requires for the purposes of exercising Operational Control of the ISO Controlled Grid.

4.6.2 **Confidentiality.** The parties to this Agreement shall implement Section 4.6.1 in conformity with the confidentiality requirements of Section 26.3.

4.7. Termination of ISO's Operational Control.

4.7.1 **Release from ISO's Operational Control.** Subject to Section 4.7.2, the ISO may relinquish its Operational Control over any transmission lines and associated facilities constituting part of the ISO Controlled Grid if, after consulting the Participating TOs owning or having Entitlements to them, the ISO determines that it no longer requires to exercise Operational Control over them in order to meet its Control

Area responsibilities and they constitute:

i. directly assignable radial lines and associated facilities interconnecting Generation (other than lines and facilities interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support);

ii. lines and associated facilities which, by reason of changes in the configuration of the ISO Controlled Grid, should be classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test, or should otherwise be excluded from the facilities subject to ISO Operational Control consistent with FERC established criteria; or

iii. lines and associated facilities which are to be retired from service in accordance with Good Utility Practice.

4.7.2 **Procedures.** Before relinquishing Operational Control over any transmission lines or associated facilities pursuant to section 4.7.1, the ISO shall inform the public through WEnet and the ISO internet website of its intention to do so and of the basis for its determination pursuant to Section 4.7.1. The ISO shall give interested parties not less than 45 days within which to submit written objections to the proposed removal of such lines or facilities from the ISO's Operational Control. If the ISO cannot resolve any timely objections to the satisfaction of the objecting parties and the Participating TOs owning or having Entitlements to the lines and facilities, such parties, Participating TOs, or the ISO may refer any disputes for resolution pursuant to the ISO ADR Procedures in Section 13 of the ISO Tariff. Alternatively, the ISO may apply to FERC for its approval of the ISO's proposal.

4.7.3 **Duty to Update ISO Register.** The ISO shall promptly record any change in Operational Control pursuant to this Section 4.7 in the ISO Register in accordance with Section 4.2.3.

5. INDEPENDENT SYSTEM OPERATOR

5.1. Control Area Operator.

5.1.1 **Membership of WSCC and RTGs.** 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 Regional Transmission Groups (RTGs) in that capacity. No Party shall take any position before the WSCC or an RTG that is inconsistent with a binding decision reached through the dispute resolution process referenced in Section 15, provided that the scope of the decision was no greater than the issues set forth in the statement of claims published by the ISO pursuant to Section 13.2.2 of the ISO Tariff.

5.1.2 **Operational Control.** The ISO shall exercise Operational Control over the ISO Controlled Grid for the purpose of:

i. providing a framework for the efficient transmission of electricity across the ISO Controlled Grid in accordance with the ISO Tariff;

ii. securing compliance with all Applicable Reliability Criteria;

iii. scheduling transactions for Market Participants to provide open and non-discriminatory access to the ISO Controlled Grid in accordance with the ISO Tariff;

iv. relieving Congestion; and

v. to the extent provided in this Agreement, assisting Market Participants to comply with other operating criteria, contractual obligations and legal requirements binding on them.

5.1.3 **Duty of Care.** The ISO shall have the exclusive right and responsibility to exercise Operational Control over the ISO Controlled Grid, subject to and in accordance with Applicable Reliability Criteria and the operating criteria established by the NRC operating licenses for nuclear generating units as provided in Appendix E pursuant to Section 6.4.2. The ISO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, Existing Contracts, the ISO Tariff and the Operating Procedures. The ISO shall not direct a Participating TO to take any action which would require a Participating TO to operate its transmission facilities in excess of their applicable rating as established or modified from time to time by the Participating TO pursuant to Section 6.4 except in a System Emergency where such a direction is consistent with Applicable Reliability Criteria.

5.1.4 **Operating Procedures.** The ISO shall, in consultation with the Participating TOs and other Market Participants, ~~through the ISO Grid Operations Committee~~ promulgate Operating Procedures governing its exercise of Operational Control over the ISO Controlled Grid in accordance with this Agreement. The ISO shall provide copies of the Operating Procedures and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WEnet or the ISO internet website.

5.1.5 **Applicable Reliability Criteria.** The ISO shall, in consultation with Participating TOs and other Market Participants ~~through the ISO Grid Operations Committee~~, develop and promulgate Applicable Reliability Criteria for the ISO Controlled Grid, which shall be in compliance with the reliability standards promulgated by NERC, WSCC, Local Reliability Criteria and NRC grid criteria related to operating licenses for nuclear generating units. The ISO shall provide copies of the Applicable Reliability Criteria and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WEnet or the ISO internet website.

5.1.6 **Waivers**. The ISO may grant to any Participating TO whose transmission facilities do not meet the Applicable Reliability Criteria when it becomes a party to this Agreement such waivers from the Applicable Reliability Criteria as the Participating TO reasonably requires to prevent it from being in breach of this Agreement while it brings its transmission facilities into full compliance. Such waivers shall be effective for such period as the ISO shall determine. A Participating TO who has been granted a waiver made under this Section 5.1.6 shall bring its transmission facilities into compliance with the Applicable Reliability Criteria before the expiration of the relevant waivers and in any event as soon as reasonably practical.

5.1.7 **Operational Protocols**. In exercising Operational Control over the ISO Controlled Grid, the ISO shall comply with the operational protocols to be provided in accordance with Section 6.4.2, as they may be amended from time to time to take account of the removal and relaxation of any Encumbrances to which the ISO Controlled Grid is subject. Participating TOs whose transmission lines and associated facilities are subject to Encumbrances shall make all reasonable efforts to remove or relax those Encumbrances in order to permit the operational protocols to be amended in such manner as the ISO may reasonably require, to the extent permitted by Existing Contracts and applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements.

5.1.8 **System Emergencies.** 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.

5.1.9 **Reporting Criteria.** The ISO shall comply with the reporting requirements of the WSCC, NERC, NRC and regulatory bodies having jurisdiction over it. Participating TOs shall provide the ISO with information that the ISO may require to meet this obligation.

5.2. Monitoring.

5.2.1 **System Requirements.** The ISO shall establish reasonable metering, monitoring, and data collection standards and requirements for the ISO Controlled Grid, consistent with WSCC and NERC standards.

5.2.2 **System Conditions.** The ISO shall monitor and observe real time system conditions throughout the ISO Controlled Grid, as well as key facilities in other areas of the WSCC region.

5.2.3 **Power Management System.** The ISO shall install a computerized Power Management System (PMS) to monitor transmission facilities in the ISO Controlled Grid. A Participating TO may at its own expense and for its own internal management purposes install a read only PMS workstation that will provide the Participating TO with the same displays the ISO uses to monitor the Participating TO's transmission facilitates.

5.2.4 **Data.** Unless otherwise mutually agreed, the ISO shall obtain real time monitoring data for the facilities listed in the ISO Register from the Participating TOs through transfers to the ISO of data available from the Energy Management Systems (EMS) of the Participating TOs.

5.3. Coordination Role.

The ISO shall perform a WSCC security coordinator function as designated by the WSCC. As such, the ISO shall have all necessary powers as described in this Agreement in relation to Participating TOs to meet the applicable NERC and WSCC requirements for security coordinators. The ISO shall assume this responsibility concurrent with the commencement of ISO Operational Control.

5.4. Public Information.

5.4.1 **WEnet.** The ISO shall develop a public information board ("WEnet" or ISO internet website) for the ISO Controlled Grid in accordance with the provisions in Section 6 of the ISO Tariff.

5.4.2 **Access to ISO Information.** The ISO shall permit the general public to inspect and copy other information in its possession, other than information to be kept confidential under Section 26.3, provided that the costs of providing documents for inspection, including any copying costs, shall be borne by the requester.

5.5. Costs

The ISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on a Participating TO without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by a Participating TO of capital and operation and maintenance costs incurred to comply with ISO-imposed reliability requirements, operating requirements, or performance standards, the ISO shall, at the request of the Participating TO, provide specific information regarding the nature of, and need for, the ISO-imposed requirements or standards to enable the Participating TO to use this information in support of cost recovery through rates and tariffs.

6. PARTICIPATING TRANSMISSION OWNERS

6.1. Physical Operation of Facilities.

6.1.1 **Operation.** Each Participating TO shall have the exclusive right and responsibility to operate and maintain its transmission facilities and associated switch gear and auxiliary equipment (including facilities that it operates under Entitlements).

6.1.2 **ISO Operating Orders.** Each Participating TO shall operate its transmission facilities in compliance with ISO Protocols, the Operating Procedures (including emergency procedures in the event of communications failure) and 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 TO 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 seek confirmation of the relevant ISO order.

6.1.3 **Duty of Care**. In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, ISO Protocols, the Operating Procedures and the Applicable Reliability Criteria.

6.1.4 **Outages**. Each Participating TO shall obtain approval from the ISO before taking out of service and returning to service any facility identified pursuant to Section 4.2.1 in the ISO Register, except in cases involving immediate hazard to the safety of personnel and the general public or imminent damage to facilities where there is not time to contact the ISO. The Participating TO shall promptly notify the ISO of such situations.

6.1.5 **Return to Service**. After a System Emergency or Forced Outage, the Participating TO shall restore to service the transmission facilities under the ISO's Operational Control as soon as possible and in the priority order determined by the ISO. The ISO's Operating Procedures shall give priority to restoring offsite power to nuclear generating units, in accordance with criteria specified by the Participating TOs under the design basis and licensing requirements of the NRC licenses applicable to such nuclear units and any other Regulatory Must-Run Generation whose operation is critical for the protection of wildlife and the environment.

6.1.6 **Written Report**. Within a reasonable time, the Participating TO shall provide the ISO with a written report, consistent with Section 17, describing the circumstances and the reasons for any Forced Outage, including outages under Section 6.1.4.

6.2. Transmission Service.

6.2.1 **Compliance with Tariffs.** Participating TOs shall allow access to their transmission facilities (including any that are not for the time being under the ISO's Operational Control) only on the terms of the ISO Tariff and the TO Tariff.

6.2.2 **Release of Scheduling Rights.** When required by the ISO, a Participating TO shall release all of its scheduling rights over the transmission lines and associated facilities that are part of the ISO Controlled Grid to the extent such rights are established through Existing Contracts among or between Participating TOs, as provided in the ISO Tariff.

6.3. Other Responsibilities.

Each Participating TO shall inspect, maintain, repair, replace and maintain the rating and technical performance of its facilities under the ISO's Operational Control in accordance with the Applicable Reliability Criteria (subject to any waivers granted pursuant to Section 5.1.6) and the performance standards established under Section 14.

6.4. Technical Information and Protocols.

6.4.1 **Information to be Provided.** Each Participating TO shall provide to the ISO prior to the effective date of this Agreement, and in a format acceptable to the ISO:

i. Technical specifications for any facilities under the ISO's Operational Control, as the ISO may require;

ii. The applicable ratings of all transmission lines and associated facilities listed in Appendix A; and

iii. A copy of each document creating an Entitlement or Encumbrance.

The Participating TO shall promptly notify the ISO in writing or mutually acceptable electronic format of any subsequent changes in such technical specifications, ratings, Entitlements or Encumbrances.

6.4.2 **Protocols for Encumbered Facilities.** A Party that is placing a transmission line or associated facility (including an Entitlement) that is subject to an Encumbrance under the Operational Control of the ISO shall develop protocols for its operation which shall: (1) reflect the rights the Party has in such facility, and (2) give effect to any Encumbrance on such facility. Such protocols shall be delivered to the ISO for review not less than ninety (90) days prior to the date on which the ISO is expected to assume Operational Control of any such facility. The ISO shall review each protocol and shall cooperate with the relevant Party to assure that operations pursuant to the protocol are feasible and that the protocol is consistent with the applicable rights and Encumbrances. To the extent such protocol is required to be filed at FERC, the relevant Transmission Owner shall file such protocol not less than sixty (60) days prior to the date on which the ISO is expected to assume Operational Control of the relevant facility. Protocols to implement the operating criteria established by the NRC operating licenses for nuclear generating units are provided in Appendix E.

6.5. EMS/SCADA System.

Each Participating TO shall operate and maintain its EMS/SCADA systems and shall allow the ISO access to the Participating TO's data from such systems relating to the facilities under the ISO's Operational Control. The ISO, at its own cost, may, if it considers it necessary for the purpose of carrying out its responsibilities under this Agreement, acquire, install and maintain additional monitoring equipment on any Participating TO's property.

6.6. Single Point Of Contact.

Each Participating TO shall provide the ISO with an appropriate single point of contact for the coordination of operations under this Agreement.

7. SYSTEM OPERATION AND MAINTENANCE

7.1. Scheduled Maintenance.

The Parties shall forecast and coordinate Maintenance Outage plans in accordance with Section 2.3.3 of the ISO Tariff.

7.2. Exercise of Contractual Rights.

In order to facilitate Maintenance Outage coordination of the ISO Controlled Grid by the ISO, each Participating TO shall, to the extent that the Participating TO has contractual rights to do so: (1) coordinate Maintenance Outages with Non-Participating Generators; and (2) exercise its contractual rights to require maintenance by Non-Participating Generators in each case in such manner as the ISO approves or requests. The requirements of this Section 7.2 shall not apply to any Non-Participating Generator with a rated capability of less than 50 MW.

7.3. Unscheduled Maintenance.

7.3.1 **Notification.** A Participating TO shall notify the ISO of any faults on the ISO Controlled Grid or any actual or anticipated Forced Outages as soon as it becomes aware of them, in accordance with Section 2.3.3 of the ISO Tariff.

7.3.2 **Returns to Service**. The Participating TO shall take all steps necessary, consistent with Good Utility Practice and in accordance with the ISO Tariff and ISO Protocols, to prevent Forced Outages and to return to operation, as soon as possible, any facility under the ISO's Operational Control that is the subject of a Forced Outage.

8. AUXILIARY EQUIPMENT AND ISO CONTROLLED GRID CRITICAL PROTECTIVE SYSTEMS

8.1. Designations of Auxiliary Equipment and Critical Protective Systems.

8.1.1 **System Security**. The ISO shall exercise Operational Control over all facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security. These will be designated as ISO Controlled Grid Critical Protective Systems. Participating TOs shall coordinate with the ISO, Generators and UDCs to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with Participating TO's, Generator's and UDC's protective systems.

8.1.2 **Remedial Action Schemes**. The ISO shall exercise Operational Control over Remedial Action Schemes that are designated as ISO Controlled Grid Critical Protective Systems. Participating TOs who are parties to contracts affecting Remedial Action Schemes shall make all reasonable efforts to amend those contracts in order to permit the relevant Remedial Action Scheme to be operated in such manner as the ISO may reasonably require.

8.1.3 **Identification.** The ISO, in conjunction with each Participating TO shall identify and designate all ISO Controlled Grid Critical Protective Systems operating in relation to its transmission facilities. The ISO may change the designation of facilities and sites as ISO Controlled Grid Critical Protective Systems from time to time.

8.2. Operation and Maintenance of Auxiliary Equipment and Critical Protective Systems.

8.2.1 **Operation and Maintenance.** The system operation and maintenance coordination functions, including ISO Maintenance Outage authorization requirements set forth in the ISO Tariff, shall apply to auxiliary equipment associated with the facilities identified in the ISO Register.

8.2.2 **Settings and Functionality.** Each Participating TO shall maintain the settings or functionality of ISO Controlled Grid Critical Protective Systems and shall not change or disable such settings or functionality without the prior written agreement of the ISO.

8.2.3 **Protective Relay Systems.** Each Participating TO shall continue to install, modify, maintain, repair and replace protective relay systems on all of the facilities identified in Appendix A, in accordance with sound engineering judgment, WSCC and NERC criteria and Good Utility Practice.

8.2.4 **Non-ISO Controlled Grid Critical Protective Systems.** Each Participating TO may alter the settings and functionality of protective relay systems and

Remedial Action Schemes that have not been designated as ISO Controlled Grid Critical Protective Systems without the consent of the ISO, provided that such changes do not reduce the normal or emergency rating of a facility identified in the ISO Register. If the facility rating will be reduced, the Participating TO shall obtain approval of the ISO prior to making such changes. In addition, the Participating TO shall promptly report to the ISO any facility rating increases that result from any changes to its protective relay settings or Remedial Action Schemes.

8.2.5 **Consistency**. The ISO shall develop in consultation with Participating TOs a consistent approach to protective system design and philosophy throughout the ISO Controlled Grid to the extent that it is practical and cost effective.

9. SYSTEM EMERGENCIES

9.1. ISO Management of Emergencies.

The ISO shall manage a System Emergency pursuant to the provisions of Section 2.3.2 of the ISO Tariff. The ISO may carry out unannounced tests of System Emergency procedures pursuant to the ISO Tariff.

9.2. Management of Emergencies by Participating TOs.

9.2.1 **ISO Orders**. In the event of a System Emergency, the Participating TOs shall comply with all directions from the ISO regarding the management and alleviation of the System Emergency unless such compliance would impair the health or safety of personnel or the general public.

9.2.2 **Communication**. During a System Emergency, the ISO and Participating TOs shall communicate through their respective control centers, in accordance with the Operating Procedures.

9.3. System Emergency Reports: TO Obligations.

9.3.1 **Records.** Pursuant to Section 17, each Participating TO shall maintain appropriate records pertaining to a System Emergency.

9.3.2 **Review.** Each Participating TO shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3 of the ISO Tariff and Section 17 of this Agreement.

9.4. Sanctions.

In the event of a major Outage that affects at least 10 percent of the customers of an entity providing local distribution service, the ISO may order a Participating TO to pay appropriate sanctions, as filed with and approved by FERC in accordance with Section 12.3, if the ISO finds that the operation and maintenance practices of the Participating TO, with respect to its transmission lines and associated facilities that it has placed under the ISO's Operational Control, prolonged the response time or was responsible for the Outage.

10. ISO CONTROLLED GRID ACCESS AND INTERCONNECTION

10.1. ISO Controlled Grid Access and Services.

10.1.1 **Access.** The ISO shall respond to requests from the Participating TOs and other Market Participants for access to the ISO Controlled Grid. All Participating TOs who have Eligible Customers connected to their transmission or distribution facilities that do not form part of the ISO Controlled Grid shall ensure open and non-discriminatory access to those facilities for those Eligible Customers through the implementation of an open access tariff, provided that a Participating TO shall only be required to ensure open access to those facilities for End-Use Customers to the extent it is required by applicable law to do so or pursuant to a voluntary offer to do so.

10.2. Interconnection.

10.2.1 **Obligation to Interconnect.** The Parties shall be obligated to allow interconnection to the ISO Controlled Grid in a non-discriminatory manner, subject to the conditions specified in this Section 10 and the applicable legal requirements.

10.2.2 **Standards.** All Interconnections shall be designed and built in accordance with Good Utility Practice, all Applicable Reliability Criteria, and applicable statutes and regulations.

10.2.3 **System Upgrades.** A Participating TO shall be entitled to require a entity requesting Interconnection to pay for all necessary system reliability upgrades on its side of the Interconnection and on the ISO Controlled Grid, as well as for all required studies, inspection and testing, to the extent permitted by FERC policy. The entity requesting Interconnection shall be required to execute an Interconnection Agreement in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff, and must comply with all of ~~its~~ their provisions, including provisions related to creditworthiness and payment for Facility Studies.

10.2.4 A Local Furnishing Participating TO shall not be obligated to construct or expand interconnection facilities or system upgrades unless and until the conditions stated in Section 4.1.2 hereof have been satisfied.

10.3. ~~Participating TO~~ Interconnections Responsibilities~~.~~

~~**Interconnections.**~~

10.3.1 **Applicability**. The provisions of this Section 10.3 shall apply only to those facilities over which a Participating TO has legal authority to effectuate proposed interconnections to the ISO Controlled Grid. Where a Participating TO does not have the legal authority to compel interconnection, the Participating TO's obligations with respect to interconnections shall be as set forth in its Commission approved TO Tariff which shall contain an obligation for the Participating TO, at a minimum, to submit or assist in the submission of, expansion and/or interconnection requests from third parties to the appropriate bodies of a project pursuant to the individual project agreements to the full extent allowed by such agreements and the applicable laws and regulations.

10.3.2 **Technical Standards**. Each Participating TO shall develop technical standards for the design, construction, inspection, and testing applicable to proposed Interconnections of Load and/or Generation Unit and apparatus to that part of the ISO Controlled Grid Facilities owned by the Participating TO. Such standards shall be consistent with Applicable Reliability Criteria and shall be developed in consultation with the ISO. The Participating TO shall periodically review and revise its criteria to ensure compliance with Applicable Reliability Criteria.

10.3.3~~2~~ **Review of Participating TO Technical Standards**. Participating TOs shall provide the ISO with copies of their technical standards for Interconnection developed pursuant to Section 10.3.2 of this Agreement and all amendments so that the ISO can satisfy itself as to their compliance with the Applicable Reliability Criteria. The ISO shall develop consistent Interconnection standards across the ISO Controlled Grid.

to the extent possible given the circumstances of each Participating TO, in consultation with Participating TOs. Any differences in Interconnection standards shall be addressed through negotiations and dispute resolution proceedings, as set forth in the ISO Tariff, between the ISO and the Participating TO.

10.3.4 **Notice**. A list of the Interconnection standards and procedures developed by each Participating TO pursuant to Section 10.3.2~~1~~, including any revisions, shall be made available to the public through the information board (e.g. WEnet or ISO internet website). In addition, the posting will provide information on how to obtain the Interconnection standards and procedures. The Participating TO shall provide these standards to any party, upon request.

10.3.5~~3~~ **~~Requests for~~ Interconnection**. Each Participating TO and the ISO shall process Interconnection requests in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff. Any differences in the procedures for interconnection contained in the ISO Tariff and the TO Tariff shall be addressed through negotiations and dispute resolution procedures, as set forth in the ISO Tariff, between the ISO and the Participating TO. ~~accept requests for new or modified Interconnections to the ISO Controlled Grid, and shall process such requests in a timely, non-discriminatory manner in accordance with its tariffs and procedures. In this regard, the Participating TO shall:~~

~~i. collect all relevant data required to process the request;~~

~~ii. coordinate the processing of the Interconnection requests with the ISO, including collecting and submitting to the ISO all information necessary for the ISO~~

~~to assess the Interconnection request;~~

~~iii. enter into system impact or Facilities Study Agreements in accordance with the applicable TO Tariff with the entity requesting Interconnection, in order to perform the studies necessary to assess the impact of the Interconnection on the ISO Controlled Grid and identify the facilities and any necessary reinforcements of the ISO Controlled Grid, including any alternative reinforcement options identified by the party requesting the Interconnection, that are required for the Interconnection;~~

~~iv. enter into agreements governing the operation of the requested Interconnection and agreements for construction, where applicable;~~

~~v. explain available study and timing options to the entity requesting Interconnection;~~

~~vi. provide a detailed estimate of the costs to be paid by the party requesting Interconnection and a statement of the proposed method of allocating the cost of any required system upgrades between that party and any other beneficiaries; and~~

~~vii. provide to the entity requesting Interconnection all ISO comments, including any additional ISO-imposed requirements.~~

~~10.3.4 **Coordination of Interconnection Requests**. To ensure that all Interconnection requests are processed in a non-discriminatory manner, the Participating TO shall develop, periodically review, and revise procedures for coordinating Interconnection requests consistent with Section 5.2 of the TO Tariff. Such procedures will specify: (1) the timing for processing requests of differing complexity; and (2) the sequencing of coordinating activities with the ISO. In addition, the~~

~~Participating TO shall coordinate the operational aspects of such Interconnection with the ISO.~~

10.3.<u>6</u>~~5~~ **Acceptance of Interconnection Facilities.** The Participating TO shall perform all necessary site inspections, review all relevant equipment tests, and ensure that all necessary agreements have been fully executed prior to accepting Interconnection facilities for operation.

10.3.<u>7</u>~~6~~ **Collection of Payments.** The Participating TO shall collect all payments owed under any <u>System Impact Study Agreement,</u> Facility Study Agreement or other agreement entered into pursuant to this Section 10.3 or the provisions of <u>the ISO Tariff and</u> its TO Tariff <u>as applicable</u> relating to Interconnection.

~~**10.4. ISO Responsibilities - Interconnections.**~~

~~**10.4.1 Review of Participating TO Technical Standards.** Participating TOs shall provide the ISO with copies of their technical standards for Interconnection developed pursuant to Section 10.3.1 of this Agreement and all amendments so that the ISO can satisfy itself as to their compliance with the Applicable Reliability Criteria. The ISO shall develop consistent Interconnection standards across the ISO Controlled Grid, to the extent possible given the circumstances of each Participating TO, in consultation with Participating TOs through the ISO Grid Operations Committee.~~

~~**10.4.2 Coordination with Participating TOs.** The ISO shall coordinate with each Participating TO in processing Interconnection requests. In that regard, the ISO shall (1) review each Participating TO's current procedures for coordinating Interconnection requests made in accordance with Section 10.3.4, (2) review individual Interconnection requests and all related Participating TO studies, and (3) forward any~~

~~comments or additional requirements to the Participating TO for transmittal to the entity requesting Interconnection.~~

10.3.8~~4.3~~ **On-Site Inspections.** The ISO may at its own expense accompany a Participating TO during on-site inspections and tests of Interconnections or, by pre-arrangement, may itself inspect Interconnections or perform its own additional inspections and tests.

10.4~~5.~~ Joint Responsibilities.

The Parties shall share with the ISO relevant information about Interconnection requests and coordinate their activities to ensure that all Interconnection requests are processed in a timely, non-discriminatory fashion and that all Interconnections meet the operational and reliability criteria applicable to the ISO Controlled Grid. Subject to Section 26.3 of this Agreement, the ISO shall pass on such information to any Parties who require it to carry out their responsibilities under this Agreement.

11. EXPANSION OF TRANSMISSION FACILITIES

The provisions of Section 3.2 of the ISO Tariff will apply to any expansion or reinforcement of the ISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the ISO.

12. USE AND ADMINISTRATION OF THE ISO CONTROLLED GRID

12.1. Use of the ISO Controlled Grid.

Except as provided in Section 13, use of the ISO Controlled Grid by the

Participating TOs and other Market Participants shall be in accordance with the rates, terms, and conditions established in the ISO Tariff and the Participating TO's Tariff. Pursuant to Section 2.1.2 of the ISO Tariff transmission service shall be provided only to direct access and wholesale customers eligible under state and federal law.

12.2. Administration.

Each Participating TO transfers authority to the ISO to administer the terms and conditions for access to the ISO Controlled Grid and to collect, among other things, Congestion Management revenues, and Wheeling-Through and Wheeling-Out revenues.

12.3. Incentives and Penalty Revenues.

The ISO, in consultation with the Participating TOs, shall develop standards and a mechanism for paying to and collecting from Participating TOs incentives and penalties that may be assessed by the ISO. Such standards and mechanism shall be filed with FERC and shall become effective upon acceptance by FERC.

13. EXISTING AGREEMENTS

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff will apply to the treatment of transmission facilities of a Participating TO under the Operational Control of the ISO which are subject to transmission service rights under Existing Contracts. In addition, the ISO will honor the operating obligations as specified by the Participating TO, pursuant to Section 6.4.2 of this Agreement, including any provision of interconnection, integration, exchange, operating, joint ownership and joint participation agreements, when operating the ISO Controlled Grid.

14. MAINTENANCE STANDARDS

14.1. ISO Determination of Standards.

The ISO shall adopt, in consultation with the Participating TOs through ~~the ISO Grid Operations~~ the Maintenance Coordination Committee, standards for the maintenance, inspection, repair, and replacement of transmission facilities under its Operational Control in accordance with Appendix C. These standards, which shall be performance-based or prescriptive or both, will provide for high quality, safe, and reliable service and shall take into account costs, local geography and weather, the Applicable Reliability Criteria, national electric industry practice, sound engineering judgment and experience.

14.2. Existing Standards.

Until such time as the ISO adopts standards pursuant to Section 14.1, the ISO shall measure the performance of Participating TOs in relation to the maintenance, inspection, repair and replacement of transmission facilities by their existing standards. Each Participating TO shall provide the ISO with such information as the ISO shall require to identify such Participating TO's existing maintenance standards and measure its performance against the relevant standards.

14.3. Availability Formula.

14.3.1 **Availability Measure.** The ISO performance-based standards shall be based on the availability measures described in Section 4 of Appendix C of this Agreement.

14.3.2 **Excluded Events.** Scheduled Approved Maintenance Outages and certain Forced Outages will be excluded pursuant to Section 4.2.3 of Appendix C of this Agreement from the calculation of the availability measure.

14.3.3 **Availability Measure Target.** ~~Under the oversight of the ISO Grid Operations Committee, t~~The Maintenance Coordination Committee and each Participating TO shall jointly develop for the Participating TO an availability measure target, which may be defined by a range. The target will be based on prior Participating TO performance developed in accordance with Section 4 of Appendix C of this Agreement and national benchmarks.

14.3.4 **Calculation of Availability Measure.** The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will determine the availability measure in accordance with Section 4 of Appendix C of this Agreement.

14.3.5 **Compliance with Availability Measure Target.** The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.3.6 **Public Record.** The Participating TO's annual availability measure calculation and the associated availability measure data shall be made available to the public.

14.4. Revisions to Standards.

The ISO shall periodically review with the Participating TOs the standards and incentives implemented pursuant to this Section 14 and, through the Maintenance Coordination Committee process, ~~under the oversight of the ISO Grid Operations~~

~~Committee,~~ shall modify these standards and incentives as necessary.

14.5. Incentives and Penalties.

The ISO shall, subject to regulatory approval, develop incentive programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the availability performance imposes demonstrable costs or results in demonstrable benefits for Market Participants.

15. DISPUTE RESOLUTION

In the event any dispute regarding the terms and conditions of this Agreement is not settled, the Parties shall follow the ISO ADR Procedure set forth in Section 13 of the ISO Tariff. The specific references in this Agreement to alternative dispute resolution procedures shall not be interpreted to limit the Parties' rights and obligations to invoke dispute resolution procedures pursuant to this Section 15.

16. BILLING AND PAYMENT

16.1 Application of ISO Tariff

The ISO and Participating TOs shall comply with the billing and payment provisions set forth in Section 11 of the ISO Tariff.

16.2 Refund Obligation

Each Participating TO, whether or not it is subject to the rate jurisdiction of the FERC under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its TO Tariff and do all other things required of a Participating TO to implement any FERC order related to the ISO Tariff, including any FERC order that requires the ISO to make payment adjustments or pay refunds to, or receive prior period overpayments from, any Participating TO. All such refunds and adjustments shall be made, and all other actions taken, in accordance with the ISO Tariff, unless the applicable FERC order requires otherwise.

17. RECORDS AND INFORMATION SHARING

17.1. Records Relevant to Operation of ISO Controlled Grid.

The ISO shall keep such records as may be necessary for the efficient operation of the ISO Controlled Grid and shall make appropriate records available to a Participating TO, upon request. The ISO shall maintain for not less than five (5) years: (1) a record of its operating orders and (2) a record of the contents of, and changes to, the ISO Register.

17.2. Participating TO Records and Information Sharing.

17.2.1 **Existing Standards.** Each Participating TO shall provide to the ISO in a format and at the time to be established by the ISO in coordination with the Participating TO, the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control in effect as of the date it executes this Agreement.

17.2.2 **Records.** Each Participating TO shall provide and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control and shall maintain records of all inspections, maintenance, replacement, and repairs performed on such facilities, which records shall be shared with the ISO under reasonable guidelines and procedures to be specified by the ISO~~, after consultation with the ISO Grid Operations Committee~~.

17.2.3 **Required Reports**. Pursuant to this Agreement and the provisions of the ISO Tariff, each Participating TO shall provide to the ISO timely information, notices, or reports regarding matters of mutual concern, including:

i. System Emergencies, Forced Outages and other incidents affecting the ISO Controlled Grid;

ii. Maintenance Outage requests, including yearly forecasts required by Section 2.3.3.5 of the ISO Tariff;

iii. System Planning Studies, including studies prepared in connection with Interconnections or any transmission facility enhancement or expansion; and

iv. Compliance with the inspection, maintenance, repair, and replacement standards established under Section 14.

17.2.4 **Other Reports**. The ISO may, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO within a reasonable time and in a form to be specified by the ISO.

17.2.5 **Other Market Participant Information**. At the request of the ISO, a Participating TO shall provide the ISO with non-confidential information obtained by the Participating TO from other Market Participants pursuant to contracts between the Participating TO and such other Market Participants. Such requests shall be limited to information that is reasonably necessary for the operation of the ISO Controlled Grid.

17.3. ISO System Studies and Operating Procedures.

17.3.1 **System Studies and Grid Stability Analyses.** The ISO, in coordination with Participating TOs, shall perform system operating studies or grid stability analyses to evaluate forecasted changes in grid conditions that could affect its ability to ensure compliance with the Applicable Reliability Criteria. The results and reports from such studies shall be exchanged between the ISO and the Participating TOs. Study results and conclusions shall generally be assessed annually, and shall be updated as necessary, based on changing grid and local area conditions.

17.3.2 **Grid Conditions Affecting Regulations, Permits and Licenses.** The ISO shall promulgate and maintain Operating Procedures to ensure that impaired or potentially degraded grid conditions are assessed and immediately communicated to the Participating TOs for operability determinations required by applicable regulations, permits or licenses, such as NRC operating licenses for nuclear generating units.

17.4. Significant Incident.

17.4.1 Risk of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware of the risk of significant incident, including extreme temperatures, storms, floods, fires, earthquakes, earth slides, sabotage, civil unrest, equipment outage limitations, etc., that affect the ISO Controlled Grid. The Parties shall provide information that the reporting Party reasonably deems appropriate and necessary for the other Parties to prepare for the occurrence, in accordance with Good Utility Practice.

17.4.2 Occurrence of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware that a significant incident affecting the ISO Controlled Grid has occurred. Subsequent to notification, each Party shall make available to the ISO all relevant data related to the occurrence of the significant incident. Such data shall be sufficient to accommodate any reporting or analysis necessary for the Parties to meet their obligations under this Agreement.

17.5. Review of Information and Record-Related Policies.

The ISO ~~Grid Operations Committee~~ shall review the requirements of this Section 17 annually and shall, consistent with reliability and regulatory needs, seek to standardize reasonable record keeping, reporting, and information sharing requirements.

18. GRANTING RIGHTS-OF-ACCESS TO FACILITIES

18.1. Equipment Installation.

In order to meet its obligations under this Agreement, a Party that owns, rents, or leases equipment (the equipment owner) may require installation of such equipment on property owned by another Party (the property owner), provided that the property is being used for an electric utility purpose and that the property owner shall not be required to do so if it would thereby be prevented from performing its own obligations or exercising its rights under this Agreement.

18.1.1 **Free Access.** The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, repair, upgrading, or removal for the purposes of this Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.

18.1.2 **Notice.** The equipment owner (whether ISO or Participating TO) shall provide reasonable notice to the property owner when requesting access for site assessment, coordinating equipment installation, or other relevant purposes.

18.1.3 **Removal of Installed Equipment.** Following reasonable notice, the equipment owner shall be required, at its own expense, to remove or relocate equipment, at the request of the property owner, provided that the equipment owner shall not be required to do so if it would thereby be prevented from performing its obligations or exercising its rights under this Agreement.

18.1.4 **Costs.** The equipment owner shall repair at its own expense any property damage it causes in exercising its rights and shall reimburse the property owner for any other costs that it is required to incur to accommodate the equipment owner's exercise of its rights under this Section 18.1.

18.2. Rights to Assets.

The Parties shall not interfere with each other's assets, without prior agreement.

18.3. Inspection of Facilities.

In order to meet their respective obligations under this Agreement, any Party may view or inspect facilities owned by another Party. Provided that reasonable notice is given, a Party shall not unreasonably deny access to relevant facilities for viewing or inspection by the requesting Party.

19. [INTENTIONALLY LEFT BLANK]~~ISO GRID OPERATIONS COMMITTEE~~

~~The Parties shall coordinate activities relating to ISO Controlled Grid practices and procedures using the ISO Grid Operations Committee process provided for in Article IV, Section 4 of the ISO Bylaws.~~

20. TRAINING

20.1. Staffing and Training to Meet Obligations.

Each Party shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. Each Party shall employ (or cause to be employed) only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct contained in the ISO Bylaws and approved by FERC.

20.2. Technical Training.

The ISO and the Participating TOs shall respond to reasonable requests for support and provide relevant technical training to each other's employees to support the safe, reliable, and efficient operation of the ISO Controlled Grid and to comply with any NERC or WSCC operator certification or training requirements. Examples of such technical training include, but are not limited to: (1) the theory or operation of new or modified equipment (e.g., control systems, remedial action schemes, protective relays); (2) computer and applicator programs; and (3) ISO (or Participating TO) requirements. The Parties shall enter into agreements regarding the timing, term, locations, and cost allocation for the training.

21. OTHER SUPPORT SYSTEMS REQUIREMENTS

21.1. Related Systems.

The Parties shall each own, maintain, and operate equipment, other than those facilities described in the ISO Register, which is necessary to meet their specific obligations under this Agreement.

21.2. Lease or Rental of Equipment by the ISO.

Under certain circumstances, it may be prudent for the ISO to lease or rent equipment owned by a Participating TO, (e.g., EMS/SCADA, metering, telemetry, and communications systems), instead of installing its own equipment. In such case, the ISO and the Participating TO shall mutually determine whether the ISO shall lease or rent the Participating TO's equipment. The ISO and the Participating TO shall enter into a written agreement specifying all the terms and conditions governing the lease or rental, including its term, equipment specifications, maintenance, availability, liability, interference mitigation, and payment terms.

22. LIABILITY

22.1. Liability for Damages.

Except as provided for in Section 13.3.14 of the ISO Tariff and subject to Section 22.4 no Party to this Agreement shall be liable to any other Party for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this Agreement except to the extent that its negligent performance of this Agreement (including intentional breach) results directly in physical damage to property owned, operated by or under the operational control of any of the other Parties or in the death or injury of any person.

22.2. Exclusion of Certain Types of Loss.

No Party shall be liable to any other party under any circumstances whatsoever for any consequential or indirect financial loss (including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill) resulting from physical damage to property for which a party may be liable under Section 22.1.

22.3. ISO's Insurance.

The ISO shall maintain insurance policies covering part or all of its liability under this Agreement with such insurance companies and containing such policy limits and deductible amounts as shall be determined by the ISO Governing Board from time to time. The ISO shall provide all Participating TOs with details of all insurance policies maintained by it pursuant to this Section 22 and shall have them named as additional insureds to the extent of their insurable interest.

22.4. Participating TOs Indemnity.

Each Participating TO shall indemnify the ISO and hold it harmless against all losses, damages, claims, liability, costs or expenses (including legal expenses) arising from third party claims due to any act or omission of that Participating TO except to the extent that they result from intentional wrongdoing or negligence on the part of the ISO or of its officers, directors or employees. The ISO shall give written notice of any third party claims against which it is entitled to be indemnified under this Section to the Participating TOs concerned promptly after becoming aware of them. The Participating TOs who have acknowledged their obligation to provide a full indemnity shall be entitled to control any litigation in relation to such third party claims (including settlement and other negotiations) and the ISO shall, subject to its right to be indemnified against any resulting costs, cooperate fully with the Participating TOs in defense of such claims.

23. UNCONTROLLABLE FORCES

23.1. Occurrences of Uncontrollable Forces.

An Uncontrollable Force means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence. No Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to the occurrence of an Uncontrollable Force.

23.2. Obligations in the Event of an Uncontrollable Force.

In the event of the occurrence of an Uncontrollable Force, which prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Parties of such Uncontrollable Force with such notice to be confirmed in writing as soon as reasonably practicable; (2) not be entitled to suspend performance of its obligations under this Agreement to any greater extent or for any longer duration than is required by the Uncontrollable Force; (3) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligations hereunder; (4) keep the other Parties apprised of such efforts on a continual basis; and (5) provide written notice of the resumption of performance hereunder. Notwithstanding any of the foregoing, the settlement of any strike, lockout, or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the Party to this Agreement involved in such strike, lockout, or labor dispute and the requirement that a Party must use its best efforts to remedy the cause of the Uncontrollable Force and/or mitigate its effects and resume full performance hereunder shall not apply to strikes, lockouts, or labor disputes.

24. ASSIGNMENTS AND CONVEYANCES

No Party may assign its rights or transfer its obligations under this Agreement except, in the case of a Participating TO, pursuant to Section 4.4.1.

25. ISO ENFORCEMENT

In addition to its other rights and remedies under this Agreement, the ISO may if it sees fit initiate regulatory proceedings seeking the imposition of sanctions against any Participating TO who commits a material breach of its obligations under this Agreement.

26. MISCELLANEOUS

26.1. Notices.

Any notice, demand, or request in accordance with this Agreement, unless otherwise provided in this Agreement, shall be in writing and shall be deemed properly served, given, or made: (1) upon delivery if delivered in person; (2) five (5) days after deposit in the mail, if sent by first class United States mail, postage prepaid; (3) upon receipt of confirmation by return electronic facsimile if sent by facsimile; or (4) upon delivery if delivered by prepaid commercial courier service. Any Party may at any time, by notice to the other Parties, change the designation or address of the person specified to receive notice on its behalf in Appendix F. Such changes to Appendix F shall not constitute an amendment to this Agreement. Any notice of a routine character in connection with service under this Agreement or in connection with the operation of facilities shall be given in such a manner as the Parties may determine from time to time, unless otherwise provided in this Agreement.

26.2. Non-Waiver.

Any waiver at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

26.3. Confidentiality.

26.3.1 **ISO.** The ISO shall maintain the confidentiality of all of the documents, data, and information provided to it by any other Party that are treated as confidential or commercially sensitive under the confidentiality provisions of the ISO Tariff; provided, however, that the ISO shall not keep confidential: (1) information that is explicitly subject to data exchange through WEnet or the ISO internet website pursuant to Section 6 of the ISO Tariff; (2) information that the ISO or the Party providing the information is required to disclose pursuant to this Agreement, the ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) the information becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this Agreement).

26.3.2 **Other Parties.** No Party shall have a right hereunder to receive from the ISO or to review any documents, data or other information of another Party to the extent such documents, data or information are required to be kept confidential in accordance with Section 26.3.1 above, provided, however, that a Party may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose any individual Party's confidential data or information.

26.3.3 **Disclosure.** Notwithstanding anything in this Section 26.3 to the contrary, if the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 26.3, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify the affected Party or Parties of the requirement and the terms thereof. The affected Party or Parties may, at their sole discretion and own costs, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Party or Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Parties to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

26.4. Third Party Beneficiaries.

The Parties do not intend to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, covenant, obligation, or undertaking established hereunder.

26.5. Relationship of the Parties.

The covenants, obligations, rights, and liabilities of the Parties under this Agreement are intended to be several and not joint or collective, and nothing contained herein shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation, or liability on, or with regard to, any of the Parties. Each Party shall be individually responsible for its own covenants, obligations, and liabilities under this Agreement. No Party or group of Parties shall be under the control of or shall be deemed to control any other Party or Parties. No Party shall be the agent of or have the right or power to bind any other Party without its written consent, except as expressly provided for in this Agreement.

26.6. Titles.

The captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

26.7. Severability.

If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

26.8. Preservation of Obligations.

Upon termination of this Agreement, all unsatisfied obligations of each Party shall be preserved until satisfied.

26.9. Governing Law.

This Agreement shall be interpreted, governed by and construed under the laws of the State of California, without regard to the principles of conflict of laws thereof, or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

26.10. Construction of Agreement.

Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against any Party, but shall be construed in a manner that most accurately reflects the purpose of this Agreement and the nature of the rights and obligations of the Parties with respect to the matter being construed.

26.11. Amendment.

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.

26.12. Appendices Incorporated.

The several appendices to this Agreement, as may be revised from time to time, are attached to this Agreement and are incorporated by reference as if herein fully set forth.

26.13. Counterparts.

This Agreement may be executed in one or more counterparts, which may be executed at different times. Each counterpart, which shall include applicable individual Appendices A, B, C, D and E shall constitute an original but all such counterparts together shall constitute one and the same instrument.

27. SIGNATURE PAGE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

California Independent System Operator Corporation has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of __________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendices A

Appendices B

Appendix C

Appendix D

Appendices E

Appendix F

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
151 Blue Ravine Road
Folsom, California 95630

by:___________________________________

Terry M. Winter
President and Chief Executive Officer

28. SIGNATURE PAGE

PACIFIC GAS AND ELECTRIC COMPANY

Pacific Gas and Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of ___________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (PG&E)

Appendix B (PG&E)

Appendix C

Appendix D

Appendix E (Diablo Canyon)

Appendix F

PACIFIC GAS ~~&~~ AND ELECTRIC COMPANY
77 Beale Street
San Francisco, California 94105

by: ________________________________

~~DeAnn Hapner~~Karen A. Tomcala
Vice President, Regulatory Relations

29. SIGNATURE PAGE

SAN DIEGO GAS & ELECTRIC COMPANY

San Diego Gas & Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ________________ day of ___________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (SDG&E)

Appendix B (SDG&E)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court
San Diego, California 92123

by: ______________________________________

James Avery~~Debra L. Reed~~
Senior Vice President of San Diego Gas & Electric

30. SIGNATURE PAGE

SOUTHERN CALIFORNIA EDISON COMPANY

Southern California Edison Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of __________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Edison)

Appendix B (Edison)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

by: ________________________________

Richard M. Rosenblum
Senior Vice President, Transmission & Distribution

~~This Agreement Is Effective As To Vernon, Upon Vernon's Unconditional Execution Of This Agreement.~~

31. SIGNATURE PAGE

CITY OF VERNON

CITY OF VERNON has caused this Transmission Control Agreement to be executed by its duly authorized representative on this _______________ day of ___________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Vernon)

Appendix B (Vernon)

Appendix C

Appendix D

Appendix E

Appendix F

CITY OF VERNON

By:______________________________
LEONIS C. MALBURG, Mayor

ATTEST:

____
BRUCE V. MALKENHORST, City Clerk

APPROVED AS TO FORM:

____
EDUARDO OLIVO, City Attorney

32. SIGNATURE PAGE

CITY OF ANAHEIM

CITY OF ANAHEIM has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____________ day of ____________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Anaheim)

Appendix B (Anaheim)

Appendix C

Appendix D

Appendix F

CITY OF ANAHEIM

By: ______________________

Marcie L. Edwards
Public Utilities General Manager

ATTEST:

____

APPROVED AS TO FORM:

____

33. SIGNATURE PAGE

CITY OF AZUSA

CITY OF AZUSA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of ____________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Azusa)

Appendix B (Azusa)

Appendix C

Appendix D

Appendix F

CITY OF AZUSA

By: ______________________________
Cristina C. Madrid
Mayor

34. SIGNATURE PAGE

CITY OF BANNING

CITY OF BANNING has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of ____________, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Banning)

Appendix C

Appendix D

Appendix F

CITY OF BANNING

By: ______________________________
John Hunt
Mayor

ATTEST:

____

APPROVED AS TO FORM:

____

35. SIGNATURE PAGE

CITY OF RIVERSIDE

CITY OF RIVERSIDE has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ______________ day of ______________, 20 ____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Riverside)

Appendix B (Riverside)

Appendix C

Appendix D

Appendix F

CITY OF RIVERSIDE
3900 Main Street, 4th Floor
Riverside, California 92522

By: ______________________________
George A. Caravalho, City Manager

ATTEST:

____
City Clerk

APPROVED AS TO FORM:

____
Supervising Deputy City Attorney

TRANSMISSION CONTROL AGREEMENT

APPENDIX A

Facilities and Entitlements

(The Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO were submitted by the ISO on behalf of the Transmission Owners on March 31, 1997– any modifications are attached as follows)

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

(submitted by the ISO on behalf of Pacific Gas and Electric Company Transmission Owner)

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted by the ISO on behalf of PG&E on March 31, 1997 are amended as follows.

Item 1: Port of Oakland 115 kV Facilities

Operation Control of the transmission facilities, shown on operating diagram, East Bay Region (East Bay Division), Sheet No. 1, serving the Port of Oakland and Davis 115 kV (USN) is not to be transferred to the ISO. These are special facilities funded by and connected solely to a customer's substation and their operation is not necessary for control by the ISO pursuant to the specifications of Section 4.1.1 of the TCA.

As of the date of execution of the TCA, the California ISO and PG&E are discussing further modifications to the diagrams of transmission lines and facilities placed under the control of the ISO. A new version of the diagrams is to be filed with FERC prior to April 1, 1998. This subsequent version of the diagrams will reflect all modifications (including those described herein).

APPENDIX A2

List of Entitlements Being Placed under ISO Operational Control

(Includes only those where PG&E is a service rights-holder)

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Pacific Power & Light, SCE, SDG&E	Transmission Use Agreement - PP&L Rate Schedule with FERC	Transmission	Upon 40 years beginning approx. 1968	
2.	SCE, SDG&E	California Power Pool - PG&E Rate Schedule FERC No. 27	Power pool	Terminated	5/6/97
3.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement - PG&E Rate Schedule FERC No. 38	Transmission	4/1/2007	Both entitlement and encumbrance.
4.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan - PG&E Rate Schedule FERC No. 183	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
5.	TANC	Coordinated Operations Agreement - PG&E Rate Schedule FERC No. 146	Interconnection, scheduling, transmission	1/1/2043	Both entitlement and encumbrance.
6.	WAPA	EHV Transmission Agreement - Contract No. 2947A - PG&E Rate Schedule FERC No. 35	Transmission	1/1/2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.	Both entitlement and encumbrance.
7.	Various - See Attachment A	Western Systems Power Pool Agreement - WSPP Rate Schedule FERC No. 1	Power sales, transmission	Upon WSPP expiration	Both entitlement and encumbrance.
8.	Vernon (City of)	Transmission Service Exchange Agreement - PG&E Rate Schedule FERC No. 148	Transmission	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for service on COTP

Supplement To PG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system[1] Pacific Gas and Electric Company (PG&E) is placing under the California Independent System Operator's Operational Control will meet the Applicable Reliability Criteria in 1998,[2] except (1) for the transmission facilities comprising Path 15, which do not meet the Western Systems Coordinating Council's (WSCC) Reliability Criteria for Transmission Planning with a simultaneous outage of the Los Banos-Gates and Los Banos-Midway 500 kV lines (for south-to-north power flow exceeding 2500 MW on Path 15),[3] and (2) with respect to potential problems identified in PG&E's annual assessment of its reliability performance in accordance with Applicable Reliability Criteria, performed with participation from the ISO and other stakeholders; as a result of this process, PG&E has been developing solutions to mitigate the identified potential problems and submitting them to the ISO for approval. ~~PG&E has not yet re-assessed its reliability performance for any reliability criteria issued or revised after it performed its assessment, e.g., the new North American Electric Reliability Council (NERC) Planning Standards and Guides, released in September, 1997.~~[4]

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Based upon PG&E's substation and system load forecasts for study year 1998, historically typical generation dispatch and the Applicable Reliability Criteria, including the current applicable WSCC Reliability Criteria for Transmission Planning issued in March 1997, the PG&E Local Reliability as stated in the 1997 PG&E Transmission Planning Handbook Criteria (submitted to the California ISO Transmission Planning, in writing, on October 20, 1997), and the NERC Reliability Performance Criteria in effect at the time PG&E was assessing its system (as of June 1, 1997). PG&E may not meet the WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.

[3] The ISO will operate Path 15 so as to maintain system reliability. In accepting this notice from PG&E, the ISO agrees to work with PG&E and the WSCC to achieve a resolution respecting the WSCC long-term path rating limit for Path 15, consistent with WSCC requirements. Pending any revision to the WSCC long-term path rating limit for Path 15, the ISO will continue to operate Path 15 at the existing WSCC long-term path rating limit unless, in the judgment of the ISO:

(a) the operating limit must be reduced on a short-term (e.g., seasonal) basis to maintain system reliability, taking into account factors such as the WSCC guidelines, determination of credible outages and the Operating Capability Study Group (OCSG) study process; or

(b) the operating limit must be reduced on a real-time basis to maintain system reliability.

In determining whether the operating limit of Path 15 must be changed to maintain system reliability, the ISO shall, to the extent possible, work with the WSCC and the PTOs to reach conesensus as to any new interim operating limit.

[4] ~~PG&E will submit its reassessment, subject to the condition below, to the ISO as soon as possible but not later than August 1, 1998. If, after the exercise of reasonable diligence by PG&E in completing the reassessment, such submittal~~

Pursuant to Section 4.1.5(i), PG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of PG&E utility service pursuant to AB 1890. However, PG&E can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from PG&E's rights pursuant to its physical ownership and operation of transmission facilities.

~~cannot be provided to the ISO by August 1, 1998, PG&E shall notify the ISO of the delay and shall specify an alternative date for submission.~~

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
1.	California Companies Pacific Intertie Agreement (CCPIA)	PG&E, SDG&E	40	July 31, 2007	• 43% of the California Companies entitlements on the Pacific Intertie.
2.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	303	2040 or sooner by mutual agreement of the parties.	• Edison owns 50% of the D-C transmission facility. (Per CCPIA, this ownership is part of the California Companies entitlements on the Pacific Intertie).
3.	PP&L Agreement	PP&L, PG&E, SDG&E		2008	• California Companies are entitled to use the entire capacity on the PP&L 500kV transmission line from Malin to Indian Spring for the term of the agreement. Per CCPIA Edison is entitled to 43% of the capacity available on the Pacific Intertie.
4.	WAPA Contract with California Companies for Extra High Voltage Transmission and Exchange Service	WAPA, PG&E, SDG&E	37	January 1, 2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.	• WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to CCPIA Parties.
5.	Los Angeles-Edison Exchange Agreement	LADWP	219	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
6.	Coordinated Operations Agreement	PG&E, SDG&E, and COTP Participants	270.7	January 1, 2043	• The allocation of Available Scheduling Capability between COTP parties and PACI parties is calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
7.	Pasadena-Edison 230-KV Interconnection and Transmission Agreement	Pasadena	55	2011	• Goodrich-Gould and Goodrich-Laguna Bell 230 kV transmission line interconnect Edison's system with Pasadena's system at Pasadena's Goodrich Substation. Lines have been re-configured from arrangement shown in contract. • Edison maintains and operates Goodrich 230 kV Substation.
8.	~~Edison-MSR Victorville-Lugo/Midway Firm Transmission Service Agreement.~~[Terminated – Not Available]	~~MSR~~	~~339~~	~~December 31, 1999.~~	~~60 MW of transmission service between Marketplace and Adelanto, and Adelanto-Victorville-Lugo.~~
9.	Victorville-Lugo Interconnection Agreement	LADWP	51	2019 or sooner by mutual agreement	• 1950 MW towards Edison, 900 MW towards LADWP. Transfer capability of the interconnection is established through joint technical studies.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
10.	City-Edison Sylmar Interconnection Agreement	LADWP	307	On 5 years notice by either party any time after the termination of the City-Edison Pacific Intertie DC Transmission Facilities Agreement.	• Sylmar-Pardee #1&2, Sylmar-Gould and Sylmar-Eagle Rock 230 kV transmission line interconnections at Sylmar including circuit breakers 's-and busses. Lines have been re-configured from arrangement described in contract. • Edison owns one of the two regulating transformers at Sylmar.
11.	City-Edison Owens Valley Interconnection and Interchange Agreement	LADWP	50	On 12 months notice by either party.	• At the request of either party and by mutual agreement, LADWP's and Edison's respective systems interconnected at LADWP's Haiwee 34.5 kV Substation, may be operated in parallel, which normally operates open at Haiwee.
12.	City-Edison 400,000 kVA Interconnection Agreement (Velasco)	LADWP	215	On 3 year written notice by either party.	• Edison's portion of the normally open Laguna Bell-Velasco 230 kV transmission line from Laguna Bell to the point where ownership changes.
13.	Edison-Los Angeles Inyo Interconnection Agreement	LADWP	306	On 5 year advance written notice by either party or by mutual agreement.	• Inyo 230/115 kV Substation, Inyo Phase Shifter, Control-Inyo 115 kV transmission line and 230 kV Tap to LADWP's Owens Gorge-Rinaldi 230 kV transmission line.
14.	Edison-Los Angeles Sepulveda Canyon Power Plant Transmission Service Agreement	LADWP	280	Termination of Sepulveda Canyon Power Plant Interconnection Agreement or sooner by either party giving a one year notice.	• 9 MW of transmission service from the high voltage leads of Sepulveda Canyon Power Plant to the 230 kV bus at Sylmar.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
15.	~~Edison-Los Angeles Owens Valley Transmission Service Agreement~~ [Terminated a/o March 26, 2001 – Not Available]	~~LADWP~~	~~281~~	~~Upon the termination of Inyo Interconnection Agreement, or five years after notice by LA, or 60 days after notice by Edison.~~	~~Up to 50 MW of bi-directional transmission service between Inyo Tie and Sylmar.~~
16.	Amended and Restated IID-Edison Mirage 230 kV Interconnection Agreement	IID	314	On one year notice but not prior to the termination date of the IID-Edison Transmission Service Agreement.	• Edison's interconnection with IID at Mirage and the point of interconnection on the Devers - Coachella Valley line.
17.	IID Edison Transmission Service Agreement for Alternative Resources	IID	268	Earlier of Dec 31, 2015, or the termination date of the last Plant Connection Agreement.	• Transmission Service on IID's 230 kV system to transmit the output of QFs resources to Edison's system, via Mirage Substation.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
18.	Four Corners Principles of Interconnected Operation	APS, SRP, EPE, PSNM, TGE	47.0	None	• Generation principles for emergency service. • Edison's facility at Four Corners includes its portion of the Eldorado -Moenkopi from Eldorado to CA/NV boarder of the Eldorado-Moenkopi -Four Corners 500 kV transmission line. • Edison can separate its wholly-owned facilities from parallel operation with others under abnormal operating conditions without prior notice. • Edison can separate its wholly-owned facilities from parallel operation with others for maintenance on reasonable advance notice (see Co-tenancy Agreement for facilities). • Edison has the right to schedule emergency service from each party.
19.	Four Corners Project Co-Tenancy Agreement and Operating Agreement	APS, SRP, EPE, PSNM, TGE	47.2	2016	• Edison has co-tenancy ownership of 32% in the Four Corners 500 kV switchyard, 12% in the 345 kV switchyard and 48% in the 345/500 kV bus-tie transformer bank. • Edison has rights to sufficient capacity in the switchyards and bus-tie transformer bank to permit its entitlement to Four-Corners Project power and energy to be delivered to the point where the Eldorado-Moenkopi-Four Corners transmission line connects to the Four Corners 500 kV Switchyard. • Edison may use any unused capacity in the switchyard for any purpose, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership of the requesting co-owners.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
20.	Navajo Interconnection Principles	USA, APS, SRP, NPC, LADWP, TGE	76	None	• Generation principles for emergency service.
21	Edison - Navajo Transmission Agreement	USA, APS, SRP, NPC, LADWP, TGE	264	5/21/23	• In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency transmission service without a charge. The amount of service provided is proportional to each parties' entitlement to the total capability of the transmission system described above.
22.	ANPP High Voltage Switchyard Agreement	APS, SRP, PSNM, EPE, SCPPA, LADWP	320	2031	• Edison has 21.77% undivided ownership interest as a tenant-in-common in the ANPP High Voltage Switchyard. • Edison has rights to transmit through the ANPP High Voltage Switchyard up to its 15.8% share of generation from ANPP, or a substitute equal amount, plus any other generation up to the extent of its transmission rights in the Palo Verde-Devers 500 kV Transmission Line • Edison has additional rights to use any unused capacity in the ANPP High Voltage Switchyard, provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
23.	~~Mohave Project Co-Tenancy Agreement and Operating Agreement~~[See Eldorado System Conveyance and Cotenancy Agreement (Line No. 26)]	~~SRP, NPC, LADWP~~	~~319~~	~~July 1, 2006~~	~~Edison has co-tenancy ownership of 56% of the Mohave switchyard.~~ ~~Edison has a capacity entitlement in the Mohave switchyard equivalent to its entitlement to Mohave Project Power and energy.~~ ~~Edison may use any unused capacity in the Mohave switchyard for any purpose provided that any over subscription shall be subject to proration of the remaining capacity based on switchyard ownership of the requesting co-owners.~~
24.	Mutual Assistance Transmission Agreement	IID, APS, SDG&E	174	On 2034 or sooner by mutual agreement of the parties.	• In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on *predetermined operating procedures* set out in a separate operating bulletin.
25.	Midway Interconnection	PG&E	309	July, 1, 2007	• Edison's share of 500 kV Midway-Vincent transmission system: – Midway-Vincent #1 – Midway-Vincent #2 – Midway-Vincent #3 from Vincent Substation to mile 53, Tower 1
26.	Amended and Restated Eldorado System Conveyance and Co-Tenancy	NPC, SRP, LADWP	42426 ~~7~~	July 1, 2006	• Edison's share of Eldorado System Components: ~~Eldorado Substation, Eldorado-Mohave 500 kV line minus 700 MW and Eldorado-Mead No. 1&2 230 kV lines minus 282 MW.~~ • *Eldorado Substation: Edison Capacity Entitlement* = Eldorado Substation Capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave Capacity Entitlement [316 MW]; • Mohave Switchyard: Edison Capacity Entitlement = 884 MW; • Eldorado – Mohave 500 kV line: (Edison Capacity Entitlement – Eldorado – Mohave 500 kV line capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Mohave Capacity Entitlement [158 MW] minus LADWP Mohave

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
					Capacity Entitlement [316 MW]): • Eldorado – Mead 230 kV Line Nos. 1 & 2: (Edison Capacity Entitlement = Eldorado – Mead 230 kV Line No. 1 &2 capacity minus NPC Mohave Capacity Entitlement [222 MW] minus SRP Capacity Entitlement [158 MW].

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
27.	Sierra Pacific -Edison Silver Peak 55 kV Interconnection Agreement	Sierra Pacific	310	2016 or sooner on 90 days advance notice but not prior to the termination of Edison's Power Purchase Agree. from Chevron.	• Control-Silver Peak A&C 55 kV transmission lines. • Edison's share of the Control-Silver Peak lines is from Control Substation to the CA/NV border.
28.	WAPA-Edison 161 kV Blythe Substation Interconnection Agreement	WAPA	221	September 30, 2007 or sooner by 3 year advanced notice by either party.	• WAPA's Blythe 161 kV Substation, and Edison's Eagle Mountain-Blythe 161 kV transmission line. • Edison may transmit up to 72 MW through WAPA's Blythe Substation, via the Eagle Mountain-Blythe 161 kV transmission line .
29.	SONGS Ownership and Operating Agreements	SDG&E, Anaheim, Riverside	321	None.	• Edison's share of SONGS switchyard with termination of its 230 kV transmission lines: – SONGS - Santiago 1 and 2, – SONGS - Serrano, and – SONGS - Chino 230 kV
30.	District-Edison 1987 Service and Interchange Agreement	MWD	203	September 30, 2017 or on five years notice by either party.	• Transmission is owned by District, but is in ISO control area. If not in use by District, or the United States under existing contracts, District's Transmission Line is available to transmit any electric energy to which Edison may be entitled. • Up to 320 MW is required to supply District's Colorado River Aqueduct pump load. • District's Transmission Line is operated by the District as directed by Edison.
31.	Edison-Arizona Transmission Agreement	APS	282	On 2016 or later upon negotiation.	• Edison has ownership-like rights to the 500 kV Transmission line from the Four Corners Project to the Arizona-Nevada border. Edison also owns the 500 kV line from Arizona-Nevada border to Edison's Eldorado substation.

APPENDIX A.2: EDISON'S CONTRACT ENTITLEMENTS

	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
32.	Mead Interconnection Agreement	WAPA	308	May 31, 2017	• Edison has rights to transmit its Hoover power • Edison's facilities include Eldorado-Mead 230 kV #1 and 2 transmission lines. • Edison may request additional firm transmission service rights through Mead Substation subject to availability as determined by WAPA.
33.	Power Purchase Contract Between SCE and Midway-Sunset Cogeneration Company.	Midway-Sunset Cogeneration Company.		5/8/09	• 200 MW of capacity through Midway Substation.

Supplement to Edison Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), Southern California Edison Company (Edison) is providing notice its transmission system[1] being placed under the California Independent System Operator's (ISO) Operational Control will meet the Applicable Reliability Criteria in 1998,[2] except as noted in its bulk power program and described herein. Edison's transmission system has been developed in accordance with NERC and WSCC's reliability criteria. WSCC's most recent Log of System Performance Recommendations, dated April 15, 1997, does not show any instances where Edison's transmission system does not meet NERC and WSCC reliability criteria, absent approved exemptions.

Pursuant to Section 4.1.5 (i), Edison does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of Edison's utility service pursuant to AB 1890. However, Edison can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from Edison's rights pursuant to its physical ownership and operation of transmission facilities.

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Edison's most recent assessment is based on Edison's substation and system load forecasts for study year 1998 and criteria in effect as of September 1, 1997. Edison meets WSCC's reliability criteria except for WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high. Assessments of Edison's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2. and under schedules adopted in that process.

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

(submitted by the ISO on behalf of San Diego Gas and Electric Company Transmission Owner)

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted hereby the ISO on behalf of SDG&E are amended as follows.

Item 1: Imperial Valley Switchyard 230kV Breakers Nos. 4132 and 5132 shown in the diagram as non-SDGE facilities should be shown as SDG&E owned. Furthermore, these breakers are being placed under the operational control of the ISO.

APPENDIX A.2: SDG&E'S CONTRACT ENTITLEMENTS

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
66-020	California Companies Pacific Intertie Agreement	Edison, PG&E	20	Subject to FERC's approval and any litigation concerning term, no earlier than July 31, 2007.	7% of the California Companies entitlements on the Pacific Intertie, including delivery rights through SCE's system from Sylmar to SONGS (100 MW); and from SONGS to Sylmar (105 MW); from Midway to SONGS (161 MW); and from SONGS to Midway (109MW).
67-012	Pacific Power & Light Agreement	PP&L, PG&E, Edison		Subject to FERC's acceptance and any litigation concerning term, no earlier than 2008.	California Companies entitled to use the entire capacity on the PP&L 500 kV transmission line from Malin to Indian Spring for the term of the agreement. SDG&E is entitled to 7% of the capacity available on the Pacific Intertie.
67-100	WAPA contract with California Companies for Extra High Voltage Transmission and Exchange Service	WAPA, PG&E Edison	37	Subject to FERC's acceptance and any litigation concerning term, no earlier than January 1, 2005. May be extended at negotiated rates.	WAPA owns a 500 kV transmission line from Malin to Round Mountain. WAPA receives 400 MW of Tracy-Round Mountain transmission service. The capacity on Malin-Round Mountain not used by WAPA is available to California Companies Pacific Intertie parties.
92-000	Coordinated Operations Agreement	PG&E, Edison, and COTP participants	270.7	January 1, 2043.	The allocation of Available Scheduling Capability between COTP parties and the Companies Pacific Intertie parties calculated on a pro rata basis according to the COTP's and PACI's Rated System Transfer Capabilities as specified in the Agreement.
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	Should a contingency occur in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None.	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey Tap - Mission - Talega (2 lines) - Encina

79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy.
78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by CFE of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.
81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031.	The parties are obligated to provide mutual switchyard assistance during emergencies to the extent possible. However, in the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E California Transmission System Participation Agreement	IID		June 24, 2051.	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500 kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E – 85.64%; and IID – 14.36%.
78-003	APS-SDG&E Arizona Transmission System Participation Agreement	APS		July 31, 2031.	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS – 11%; SDG&E - 69%; IID - 20%.

Supplement To SDG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system[1] of San Diego Gas & Electric Company (SDG&E) is placing under the California Independent System Operator's Operational Control meets the Applicable Reliability Criteria,[2] with the following_exceptions: (1) SDG&E has not yet re-assessed its system performance for any reliability criteria added or modified by the new North American Electric Reliability Council (NERC) Planning Standards and Guides, released in September, 1997;[3] (2) SDG&E has also not yet re-assessed its system performance for the revised simultaneous generator outage criteria which was approved by the WSCC Board of Trustees on October 27, 1997.[4]

Pursuant to Section 4.1.5(i), SDG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of SDG&E utility service pursuant to AB 1890. However, SDG&E cannot warrant that these right-of-way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from SDG&E's rights, pursuant to its physical ownership and operation of transmission facilities.

---

[1] Including upgrades and operational plans for the transmission lines and associated facilities.

[2] Based upon studies with SDG&E's forecast peak 1998 system loads and the Applicable Reliability Criteria, including the WSCC Reliability Criteria for Transmission Planning and WSCC Minimum Operating Reliability Criteria dated March 1997, and the SDG&E Local Reliability Criteria as submitted to the California ISO by letter dated December 15, 1997.

[3] Assessments of SDG&E's transmission system using NERC Planning Standards and Guides, released September 16, 1997 will be performed in accordance with the ISO's coordinated transmission planning process as provided for in the ISO Tariff, Section 3.2.2 and under schedules adopted in that process.

[4] The revised criteria will be cooperatively assessed by SDG&E and the ISO as soon as possible but not later than May 1, 1998. SDG&E also may not meet the WSCC's Disturbance Performance level 'D' (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.

APPENDIX A.2: CITY OF VERNON

TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT/DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Vernon (Operating Agent-LA) (7)	Bi-Directional	- MAP Joint Ownership Agreement. - Adelanto Switching Station Interconnection Agreement. - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Coordinating Committee.	~~75~~81 MW
2. Mead-Phoenix Project (MPP) a) Westwing-Mead b) Mead Substation c) Mead-Marketplace	SCPPA, MSR, Vernon, SRP, APS (Operating ~~Agent~~Managers – SRP, Western (DSW)) ~~Westwing)~~ (7)	 Bi-Directional Bi-Directional Bi-Directional	- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement - Mead Interconnection *Agreement* - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Management Committee.	 28 MW 47 MW 75 MW
3. North to South on COTP South to North on COTP	Vernon, PG&E, TANC, WAPA, City of Shasta Lake, Carmichael Water District, San Juan Suburban Water District, CDWR (Operating Agent-Western (SNR)) (7)		COTP Interim Participation Agreement.		Upon execution of a superseding long-term participation agreement or upon a unanimous decision by the executing parties to terminate this Agreement.	121 MW N-S 92 MW S-N

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

[illegible]	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
4. Sylmar-Midway (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	93 MW
5. Sylmar-Laguna Bell - Through midnight December 31, 2002. - After midnight December 31, 2002.	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	93 MW 60 MW
6. Midway-Laguna Bell (After 12/31/2007).	Vernon, Edison	Bi-Directional	Edison-Vernon PDCI/COTP FTS	272	(1) See Notes	60 MW
7. Mead-Laguna Bell	Vernon, Edison	Bi-Directional	Edison-Vernon Mead FTS	207	(2) See Notes	26 MW
8. Victorville-Lugo Midpoint-Laguna Bell Note: Service is reduced to 11 MW on 1/1/2003, unless Vernon elects by 10/1/2002 to extend up to an additional 64 MW of service.	Vernon, Edison	Bi-Directional	Edison-Vernon Victorville-Lugo Midpoint FTS	154	(3) See Notes	75 MW
9. Adelanto-Victorville/Lugo Midpoint (4a)	Vernon, Los Angeles	Bi-Directional	Los Angeles-Vernon Adelanto-Victorville/Lugo FTS		(4b) See Notes	75/81 MW (8)
10. NOB-Sylmar-Midway Midway-Sylmar-NOB (6)	Vernon, PG&E	Bi-Directional	Transmission Service Exchange Agreement Between PG&E and the City of Vernon	148	(5) See Notes	93 MW N-S 82 MW S-N

Summary - Details are in each Agreement.

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

Notes:

(1) Contract Termination: Upon termination of Vernon's ownership of a portion of the COTP entitlement.

(2) Contract Termination: Upon termination of Vernon's Hoover Power Sales contract with WAPA; or 12/31/2007 based on proper notice from Vernon to Edison.

(3) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or 12/31/2007 based on proper notice from Vernon to Edison.

(4a) DWP No. 10396.

(4b) Contract Termination: Upon permanent removal from operation of the Mead-Adelanto 500 kV Transmission Project; or four years prior written notice by either party.

(5) Contract Termination:

1. This Agreement may be terminated on July 31, 2007:

    A. By PG&E with one year notice to Vernon, if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in DC Line at NOB.

    B. By Vernon, if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.

    C. If the DC Line or COTP facilities are retired.

2. In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

3. Otherwise, the Agreement remains in effect until September 2042.

APPENDIX A.2: CITY OF VERNON'S CONTRACT ENTITLEMENTS

Notes: (continued)

(6) Transfer capability at Sylmar: In accordance with Section 7.2 of the PG&E-Vernon Transmission Service Exchange Agreement and Section 6.1 of the Edison-Vernon Firm Transmission Service Agreement, Vernon receives the following transmission services:

a) 93 MW from NOB to Sylmar.
b) 82 MW from Sylmar to NOB.
c) 93 MW from Sylmar to Laguna Bell (60 MW after midnight December 31, 2002).
d) 93 MW from Laguna Bell to Sylmar (60 MW after midnight December 31, 2002).
e) 60 MW to Sylmar through the regulating transformers.
f) 53 MW from Sylmar through the regulating transformers.
g) 93 MW from Sylmar to Midway, after 12/31/2007.
h) 93 MW from Midway to Sylmar, after 12/31/2007.

(7) For information only.

(8) Effective July 1, 2002, Vernon's Entitlement on the *Adelanto-Victorville/Lugo line increases* from 75 MW to 81 MW.

APPENDIX A: CITY OF ANAHEIM
TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1	IPP-Adelanto Switching Station	Anaheim-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	339 MW
2	Marketplace Substation-Adelanto	Anaheim-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
	Marketplace Substation-McCullough	"	"	"		"	118 MW
3	Westwing-Mead 500 kV	Anaheim-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	47 MW
	Marketplace-Mead 500 kV	"	"	"		"	110 MW
	Mead 500 kV-Mead 230 kV	"	"	"		"	110 MW
	Marketplace Substation-McCullough	"	"	"		"	110 MW
4	Adelanto-Victorville/Lugo	Anaheim-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	110 MW
5	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Base Capacity Transmission Service Agreement		See Note 2	212 MW
6	Adelanto-Victorville/Lugo	Anaheim-LADWP	North-South	IPP Additional Capacity Transmission Service Agreement		See Note 3	127 MW
7	IPP-Mona Substation	Anaheim-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	370 MW
	IPP-Gonder Substation	"	"	"		"	53 MW
8	Nevada-Oregon Border-Sylmar	Anaheim-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	24 MW
9	San Juan-Four Corners	Anaheim-PNM	Bi-directional	Interconnection Agreement – Service Schedule F		See Note 5	50 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Anaheim interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Anaheim interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on termination of Anaheim's ownership interest in San Juan Generating Station Unit 4.

APPENDIX A: CITY OF AZUSA
TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT/DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Vernon	Bi-Directional	- MAP Joint Ownership Agreement. - Adelanto Switching Station Interconnection Agreement. - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Coordinating Committee.	19 MW

POINT OF RECEIPT/DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
2. Mead-Phoenix Project (MPP)	SCPPA, MSR, Vernon, SRP, APS		- MPP Joint Ownership Agreement - Westwing Substation Interconnection Agreement - Mead Interconnection Agreement - Marketplace-McCullough 500 kV Interconnection Agreement.		As agreed to by the owners and approved by the Project Management Committee.	
a) Westwing-Mead b) Mead Substation c) Mead-Marketplace		Bi-Directional Bi-Directional Bi-Directional				3 MW 0 MW 3 MW
3. Mead - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Hoover FTS	247.4	(1) See Notes	4 MW
4. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Palo Verde Nuclear Generating Station FTS	247.6	(2) See Notes	4 MW
5. Victorville-Lugo - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa Pasadena FTS	247.8	(3) See Notes	14 MW

POINT OF RECEIPT/DELIVERY	PARTIES	DIRECTION	CONTRACT TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
6. Sylmar - Rio Hondo	Azusa, Edison	Uni-Directional	Edison-Azusa San Juan Unit 3 FTS	247.29	(4) See Notes	10 MW: January – April; November – December 2003 25 MW: May – October 2003 10 MW: CY 2004 through termination
7. Mead - Rio Hondo	Azusa, Edison	Bi-Directional	Edison-Azusa Sylmar FTS	247.24	(5) See Notes	8 MW
8. Sylmar - NOB	Azusa, Pasadena, Burbank	Bi-Directional	Pacific Intertie Direct Current FTS		(6) See Notes	3MW
9. ANPP (Devers) - Sylmar	Azusa, Los Angeles	Bi-Directional	Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021	(7) See Notes	10 MW
10. Victorville-Lugo - Adelanto	*Azusa, Los Angeles*	Bi-Directional	Los Angeles - Azusa Adelanto-Victorville/Lugo FTS	DWP No. 10345	(8) See Notes	19 MW
11. Sylmar & Rio Hondo – COB	Azusa, Edison	Uni-Directional	Edison-Azusa Pacific Intertie FTS	247	(9) See Notes	15 MW

Summary- details are in each agreement.

NOTES:

(1) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement or termination of *Electric Service Contract*, *provided* that the termination of FTS Agreement shall not occur prior to January 1, 2003.

(2) Contract Termination: Upon written agreement between the Parties to terminate the FTS Agreement, termination of Azusa's entitlement to PVNGS, or termination of the Arizona Nuclear Power Project Participation, provided that the termination of the FTS Agreement shall not occur prior to January 1, 2003.

(3) Contract Termination:	Upon written agreement between the Parties to terminate the FTS Agreement or termination of City's ownership in San Juan Unit 3, *provided that termination of this* Transmission Service Agreement shall not occur prior to January 1, 2003.
(4) Contract Termination:	Same as (3)
(5) Contract Termination:	Same as (3)
(6) Contract Termination:	This agreement will be terminated effective September 30, 2009.
(7) Contract Termination:	This agreement shall be terminated upon the earlier of: (i) 2400 hours on December 31, 2023; (ii) by mutual agreement of the Parties; *(iii) thirty-six months after* Los Angeles has provided written notice that the Agreement is to terminate, provided, however, such notice of termination shall not be given prior to December 31, 2000; or (iv) Azusa may elect to discontinue service under this Agreement by written notice to Los Angeles within sixty days of the mailing date of any subsequent rate for transmission service established under *Section 10.3 of the Agreement. If Azusa so elects*, this Agreement shall terminate on the last day of the second full month following the mailing date of Azusa's notice.
(8) Contract Termination:	This agreement shall be terminated *upon the earlier of: (i) four years prior written* notice by either Party, which notice shall not be given before one year after the Date of Firm Operation; (ii)the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville-Lugo transmission line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission line, as such date is defined pursuant to the agreements *relating thereto; (v) a date determined* pursuant to Section 4.3 of the Agreement; or (vi) a date mutually agreed upon by the Parties.
(9) Contract Termination:	The agreement shall terminate on the earlier of: (i) midnight October 31, 2003; or (ii) at least one year's written notice by City to Edison, provided such notice shall be given no earlier than January 1, 2002.

APPENDIX A: CITY OF BANNING TRANSMISSION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	Marketplace Substation-Adelanto	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		Oct 31, 2030	12 MW
2.	Westwing-Mead-Marketplace 500 kV	Banning-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	3 MW
3.	Marketplace-McCullough 500 kV	Banning-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		Oct 31, 2030	12 MW 3 MW
4.	ANPP-Sylmar	Banning-LADWP	Bi-directional	ANPP/Sylmar 15 MW Transmission Service Agreement		See Note 1	15 MW
5.	Adelanto-Victorville/Lugo	Banning-LADWP	To Victorville	*Adelanto-Victorville*/Lugo Firm Transmission Service Agreement		See Note 2	12 MW
6.	Nevada-Oregon Border-Sylmar	Banning-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		Sep 30, 2009	1 MW
7.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Palo Verde Nuclear Generating Station Firm Transmission Service Agreement		See Note 3	3 MW
8.	Victorville/Lugo-Devers 115 kV	Banning-SCE	To Devers	Sylmar Firm Transmission *Service Agreement*		See Note 4	5 MW
9.	Mead 230 kV-Devers 115 kV	Banning-SCE	To Devers	Hoover Firm Transmission Service Agreement		See Note 5	2 MW
10.	Devers 500 kV-Devers 115 kV	Banning-SCE	To Devers	1995 San Juan Unit 3 Firm Transmission Service Agreement		See Note 6	15 MW
11.	Devers 500 kV-Devers 115 kV	Banning-SCE	To Devers	1997 Pasadena PSA Firm Transmission Service Agreement		Dec 31, 2003	5 MW
12.	California-Oregon Border-Sylmar	Banning-SCE	To Sylmar	*Pacific Intertie Firm Transmission Service Agreement* (Seasonal: May – October)		Oct 31, 2003	5 MW

Notes

1. Agreement terminates on: (i) December 31, 2023; or (ii) 36-months notice by LADWP.
2. *Agreement terminates on:* (i) 4-years written notice by either party; or (ii) the date of retirement of the Mead-Adelanto Project; (iii) the date the point of interconnection on the Victorville/Lugo line is permanently removed from service; (iv) the in-service date of the Adelanto-Lugo transmission *line, as such date is* defined pursuant to the agreements relating thereto.
3. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest in Palo Verde Nuclear Generating Station Unit 2; or (iii) unacceptable FERC modification.
4. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.
5. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of the Electric Service Contract between Western and Banning; *or (iii) unacceptable* FERC modification.
6. Agreement terminates on: (i) twelve months notice by Banning; (ii) termination of Banning's interest San Juan Unit 3; or (iii) unacceptable FERC modification.

APPENDIX A: CITY OF RIVERSIDE
TRANSMISION ENTITLEMENTS

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
1.	IPP-Adelanto Switching Station	Riverside-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	195 MW
2.	Marketplace Substation-Adelanto	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	118 MW
3.	Westwing-Mead-Marketplace 500 kV	Riverside-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	12 MW
4.	Marketplace-McCullough 500 kV	Riverside-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract Mead-Phoenix Project Transmission Service Contract		31-Oct-30 31-Oct-30	118 MW 12 MW
5.	Adelanto-Victorville/Lugo	Riverside-LADWP	Bi-directional	Adelanto-Victorville/Lugo 110 MW Firm Transmission Service Agmnt		See Note 1	118 MW
6.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Base Capacity Transmission Service Agreement		See Note 2	122 MW
7.	Adelanto-Victorville/Lugo	Riverside-LADWP	To Victorville	IPP Additional Capacity Transmission Service Agreement		See Note 3	73 MW
8.	IPP-Mona Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	175 MW
	IPP-Gonder Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	25 MW
9.	Nevada-Oregon Border-Sylmar	Riverside-LADWP	Bi-directional	NOB/Sylmar 25 MW Firm Transmission Service Agreement (Seasonal: June – October)		31-Oct-04	25 MW
10.	Nevada-Oregon Border-Sylmar	Riverside-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	23 MW
11.	San Onofre-Vista	Riverside-SCE	To Vista	San Onofre Nuclear Generating Station Firm Transmission Service Agmt.		See Note 5	42 MW
12.	Mead 230 kV-Vista	Riverside-SCE	To Vista	Hoover Firm Transmission Service Agreement		See Note 6	30 MW
13.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Intermountain Power Project Firm Transmission Service Agreement		See Note 7	156 MW
14.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Palo Verde Nuclear Generating Station Firm Transmission Service Agmt.		See Note 8	12 MW

Notes

1. Agreement terminates on: (i) removal of Mead-Adelanto Project from Service; or (ii) removal of Los Angeles-SCE Interconnection at Victorville/Lugo.
2. Agreement terminates on: (i) June 15, 2027; or (ii) the date Riverside interconnects at Adelanto Switching Station.
3. Agreement terminates on: (i) June 15, 2027; (ii) the date Riverside interconnects at Adelanto Switching Station; or (iii) 5-year's notice by LADWP.
4. Agreement terminates on: (i) termination of LADWP's rights to the Northern Transmission System; or (ii) termination of the IPP Additional Capacity Agreement.
5. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in San Onofre Nuclear Generating Station Units 2 and 3; or (iii) unacceptable FERC modification.
6. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Boulder Canyon Project (Hoover); or (iii) unacceptable FERC modification.
7. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Intermountain Power Project; or (iii) unacceptable FERC modification.
8. Agreement terminates on: (i) six months notice by Riverside; (ii) termination of Riverside's interest in the Palo Verde Nuclear Generating Station; or (iii) unacceptable FERC modification.

TRANSMISSION CONTROL AGREEMENT

APPENDIX B

Encumbrances

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed under ISO Operational Control (per TCA Appendix A1 & A2)[1]

(Includes only those where PG&E is a service provider)

Abbreviations Used:

CDWR	=	California Department of Water Resources
SCE	=	Southern California Edison Company
SDG&E	=	San Diego Gas & Electric Company
SMUD	=	Sacramento Municipal Utility District
TANC	=	Transmission Agency of Northern California
WAPA	=	Western Area Power Administration

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~1.~~	~~AIG Trading Corp.~~	~~Service Agreement No. 7 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~1/~~	~~Effective 3/14/97~~
~~2.~~	~~Anaheim (City of)~~	~~Economy Energy Agreement - Rate Schedule FERC No. 109~~	~~Economy energy sales~~	~~Evergreen, or on notice~~	
~~3.~~	~~Aquila Power Corp.~~	~~Service Agreement No. 11 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~1/~~	~~Effective 3/19/97~~
~~4.~~	~~Arvin-Edison ID~~	~~Distribution Service Agreement - PG&E Rate Schedule FERC No. 79~~	~~Local distribution~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005~~	
~~5.~~	~~Arizona Electric Power Cooperative~~	~~Non-Firm Energy Sales - PG&E Rate Schedule FERC No. 70~~	~~Non-firm power sales~~	~~Evergreen, or 30 day notice~~	
~~6.~~	~~Arizona Public Service~~	~~Short-Term Firm Power Sale - PG&E Rate Schedule FERC No. 50~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Voluntary non-firm power sales~~

1 The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~7.~~	~~Arizona Public Service Company~~	~~Service Agreement No. 8 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 3/10/97~~
~~8.~~	~~Azusa (City of)~~	~~Economy Energy Agreement - Rate Schedule FERC No. 110~~	~~Economy energy sales~~	~~Evergreen, or on notice~~	
~~9.~~	~~Bay Area Rapid Transit~~	~~Service Agreement No. 2, under FERC Electric Tariff, Original Volume No. 3~~	~~Firm Point-to-Point Transmission Service - OAT~~	~~11/30/96~~	~~Effective 11/8/96 agreement terminated~~
~~10.~~	~~Bay Area Rapid Transit~~	~~Service Agreement No. 3 under FERC Electric Tariff, Original Volume No. 3~~	~~Firm Point-to-Point Transmission Service - OAT~~	~~1/31/97~~	~~Effective 12/1/96, agreement terminated~~
~~11.~~	~~Bay Area Rapid Transit~~	~~Service Agreement No. 21 under FERC Electric Tariff, Original Volume No. 3~~	~~Firm Point-to-Point Transmission Service - OAT~~	~~7/31/97~~	~~Effective 5/1/97 agreement terminated~~
~~12.~~1.	Bay Area Rapid Transit	Service Agreement Nos. ~~30 under~~ 42 and 43 to FERC Electric Tariff, ~~Original~~ First Revised Volume No. 12~~3~~	~~Firm Point-to-Point Transmission Service~~ Network Integration Transmission Service Agreement and Network Operating Agreement - OAT	10/1/2016~~12/31/97~~	~~Service commenced 8/1/97 and will terminate on 12/31/97 or upon commencement of direct retail access in California. Service not to extend beyond 6/30/98.~~
~~13.~~	~~Banning (City of)~~	~~Economy Energy Agreement - Rate Schedule FERC No. 111~~	~~Economy energy sales~~	~~Evergreen, or on notice~~	
~~14.~~	~~Bonneville Power Administration~~	~~Power Sales Agreement PG&E Rate Schedule FERC No. 32~~	~~Power Purchase - Energy Exchange~~	~~No notice of termination filed with FERC~~	~~Power purchases are voluntary~~
~~15.~~	~~Bonneville Power Administration~~	~~Exchange Agreement - PG&E Rate Schedule FERC No. 33~~	~~Exchange Agreement~~	~~No notice of termination filed with FERC~~	
~~16.~~	~~Bonneville Power Administration~~	~~Capacity and Energy Exchange Agreement - PG&E Rate Schedule FERC No. 129~~	~~Capacity and Energy Exchange Agreement~~	~~No notice of termination filed with FERC~~	
~~17.~~	~~Bonneville Power Administration~~	~~Service Agreement No. 6 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~		~~Effective 3/12/97~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~18.~~	~~Calaveras County Public Power Agency~~	~~Distribution Service Agreement - PG&E Rate Schedule FERC No.75~~	~~Distribution~~	~~Evergreen, or 30 day notice~~	
~~19.~~	~~Central California Power Agency #1~~	~~Geysers Transmission - PG&E Rate Schedule FERC No.119~~	~~Transmission~~	~~11/1/97~~	
~~20.~~2.	CDWR	Comprehensive Agreement - PG&E Rate Schedule FERC No.77	Interconnection and transmission	12/31/2014~~1~~ ~~2/31/2004, but CDWR can extend through 2014~~	Transmission Related Losses
~~21.~~3.	CDWR	Etiwanda Power Plant Generation Exchange - PG&E Rate Schedule FERC No. 169	Power exchanges	Evergreen, or on 5 years notice	
~~22.~~4.	CDWR	Extra High Voltage Transmission - PG&E Rate Schedule FERC No. 36	Transmission	1/1/2005~~, subject to dispute~~	
~~23.~~	~~Citizens Lehman Power Sales~~	~~Enabling Agreement - PG&E Rate Schedule FERC No.192~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~24.~~	~~Citizens Lehman Power Sales~~	~~Service Agreement No. 13 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~*~~	~~Effective 3/25/97~~
~~25.~~	~~Cinergy Services, Inc.~~	~~Service Agreement No. 14 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~*~~	~~Effective 4/30/97~~
~~26.~~	~~Coastal Electric Services~~	~~Enabling Agreement - PG&E Rate Schedule FERC No.191~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~27.~~	~~Colton (City of)~~	~~Economy Energy Agreement - Rate Schedule FERC No. 112~~	~~Economy energy sales~~	~~Evergreen, or on notice~~	
~~28.~~	~~Constellation Power Source, Inc.~~	~~Service Agreement No. 36 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~*~~	~~Effective 9/23/97~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~29~~5.	~~Destec~~ Dynegy Power Services	Control Area Transmission Agreement - PG&E Rate Schedule FERC No. ~~185~~ 224	Transmission and various other services	Terminated 12/31/01. PG&E filing of FERC termination pending submittal of a filing to FERC. ~~3/1/1999, but may be extended to 2002~~	
~~30.~~	~~Electric Clearing-house~~	~~Enabling Agreement - PG&E Rate Schedule FERC No.184~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~31.~~	~~Enron~~	~~Enabling Agreement - PG&E Rate Schedule FERC No. 178~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~32.~~	~~Equitable Power Services Company~~	~~Service Agreement No. 22 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 6/16/97~~
~~33.*~~	~~Idaho Power Company~~	~~Service Agreement No. 10 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 3/10/97~~
~~34.~~	~~Kansas City Power & Light~~	~~Service Agreement No. 34 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 8/21/97~~
~~35.~~	~~Lassen Municipal Utility District~~	~~Power and Transmission Service Agreement - PG&E Rate Schedule FERC No. 149~~	~~Transmission~~	~~2/1/2004~~	~~Partial requirement firm sales~~
~~36~~6.	DOE Laboratories, WAPA	PG&E/WAPA/DOE-SF 10/30/98 Settlement Agreement – PG&E Rate Schedule FERC No. 147	Transmission Service	3/31/2009	
~~36~~7.	Lawrence Livermore National Laboratory, WAPA	~~Power Purchase~~ PG&E/WAPA/DOE – SF Settlement Agreement - ~~Services for Use of COTP Power –~~ PG&E Rate Schedule FERC No. 147	Standby Transmission Service~~reserve transmission sales~~	3/31/2009~~1/19/99, or 12 months notice~~	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~37.~~	~~LG&E Energy~~	~~Service Agreement No. 20 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 7/9/97~~
~~38.~~	~~Los Angeles Dept. of Water and Power~~	~~Enabling Agreement -- PG&E Rate Schedule FERC No. 141~~	~~Surplus power sales and transmission~~	~~No notice of termination filed with FERC~~	
~~39.~~	~~Metropolitan Water District, SCE~~	~~Transmission Service Agreement - SCE Rate Schedule with FERC~~	~~Transmission~~	~~4/1/2004, or upon termination of other associated contracts~~	
~~40.~~8.	Midway-Sunset Co-Generation	Cogeneration Project Special Facilities - PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
~~41.~~9.	Minnesota Methane	Service Agreement No. 1, under FERC Electric Tariff, ~~Original~~ First Revised Volume No. 12~~3~~	Firm Point-to-Point Transmission Service - OAT	10/1/2016	Effective 10/1/96
~~42.~~10.	Modesto Irrigation District	Interconnection Agreement - PG&E Rate Schedule FERC No.116	Interconnection, transmission, power sales	4/1/2008~~, subject to exception~~	Power sales are coordination sales - voluntary spot sales
~~43.~~	~~MSR Public Power Agency~~	~~Scheduling Services Contract - PG&E Rate Schedule FERC No. 187~~	~~Transmission~~	~~1/1/2014, subject to dispute~~	
~~44.~~	~~National Electric Associates, L.P.~~	~~Enabling Agreement - PG&E Rate Schedule FERC No. 193~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~45.~~	~~Nevada Power Co.~~	~~Exchange Agreement PG&E Rate Schedule FERC No. 54~~	~~Emergency, and power sales and exchanges~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory or as available~~
~~46.~~11.	NCPA, CSC, CDWR	Castle Rock-Lakeville CoTenancy Agreement - PG&E Rate Schedule FERC No. 139	Transmission facilities maintenance	Evergreen, or 1 year notice after 1/1/2015	
~~47.~~	~~NCPA~~	~~Interconnection Agreement - PG&E Rate Schedule FERC No. 142~~	~~Interconnection, transmission, power sales~~	~~9/13/2013, or 3 years notice~~	~~Option to take Partial Requirements - Firm Power with sufficient advance notice. Currently zero through 1999~~
~~48.~~	~~NorAm Energy Service, Inc.~~	~~Service Agreement No. 20 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 4/29/97~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~49.~~	~~Northern California Reliability~~	~~Priority encumbrance/reservation for power from the Pacific Northwest to maintain reliability in northern California area – north of Path 15~~	~~Varies monthly~~		~~Corresponds to past and present use of transfer capability across COB in relation to priorities under Existing Contracts for transmission service~~
~~50.~~	~~PacifiCorp~~	~~Interconnection Agreement – PG&E Rate Schedule FERC No. 195~~	~~Interconnection~~	~~7/31/2007, or 5 years notice~~	
~~51.~~	~~PacifiCorp~~	~~Service Agreement No. 18 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service – OAT~~	~~#~~	~~Effective 4/14/97~~
~~52.*~~	~~PacifiCorp~~	~~Service Agreement No. 23 under FERC Electric Tariff, Original Volume No. 3~~	~~Firm Point-to-Point Transmission Service~~	~~6/30/97~~	~~Effective 6/3/97~~
~~53.*~~	~~Pan Energy Trading~~	~~Service Agreement No. 27 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service – OAT~~	~~#~~	~~Effective 7/1/97~~
~~54.~~12.	Path 15 Operating Instructions Settlement – Various, see FERC Docket No. ER99-1770-001	Exhibit B-1 to this Appendix B to the TCA~~Use in real time is consistent with Existing Contracts and priority commitments in accordance with the South of Tesla principles. Other use is subject to Day-Ahead and Hour-Ahead congestion charges.~~	Implements curtailment priorities consistent with various Existing Transmission Contracts. Establishes Path 15 Facilitator role for PG&E.	3/13/2003	~~Preserves past and present use of Path 15 in relation to priorities under Existing Contracts for transmission service in accordance with the operating instructions provided to the ISO which are attached as Exhibit B-1..~~
~~55.~~	~~PECO Energy Company~~	~~Service Agreement No. 28 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service – OAT~~	~~#~~	~~Effective 7/3/97.~~
~~56.~~	~~Port of Oakland~~	~~Interconnection Agreement – PG&E Rate Schedule FERC No. 194~~	~~Interconnection~~	~~12/31/2000~~	
~~57.~~	~~Portland General Electric~~	~~Sales and Exchange – PG&E Rate Schedule FERC No. 51~~	~~Power sales and exchanges~~	~~Evergreen, or 5 years notice~~	~~Sales are voluntary~~
~~58.~~	~~Portland General Electric~~	~~Energy Sales and Exchange – PG&E Rate Schedule FERC No. 71~~	~~Power sales and exchanges~~	~~Evergreen, or 3 years notice~~	~~Power Sales are voluntary~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~59.~~13.	Power Exchange	Control Area Transmission Service Agreement - PG&E Rate Schedule FERC No. 186	Transmission and various other services	3/1/2000, or may extend if Destec does	
~~60.*~~	~~Powerex~~	~~Service Agreement No. 19 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 4/24/97~~
~~61.*~~	~~Powerex~~	~~Service Agreement No. 25 under FERC Electric Tariff, Original Volume No. 3~~	~~Firm Point-to-Point Transmission Service - OAT~~	~~9/30/97~~	~~Effective 7/1/97~~
~~62.~~	~~Public Service of New Mexico~~	~~Economy Energy Contract - PG&E Rate Schedule FERC No. 101~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Sales entirely optional~~
~~63.~~14.	Puget Sound Power & Light	Capacity and Energy Exchange - PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates in 2007 per 5 year advance written notice received from Puget in 2002.~~Evergreen, or 1 year notice~~	
~~64.~~	~~Rainbow Energy Marketing~~	~~Enabling Agreement - PG&E Rate Schedule FERC No. 189~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Sales entirely optional~~
~~65.~~	~~Riverside (City of)~~	~~Economy Energy Agreement - Rate Schedule FERC No. 113~~	~~Economy energy sales~~	~~Evergreen, or on notice~~	
~~66.~~	~~Salt River Project~~	~~Economy Contract - PG&E Rate Schedule FERC No. 74~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Sales are entirely optional~~
~~67.~~	~~Salt River Project~~	~~Service Agreement No. 16 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 4/7/97~~
~~68.~~15.	San Francisco (City and County of)	Interconnection Agreement - PG&E Rate Schedule FERC No. 114	Interconnection, transmission and supplemental power sales	7/1/2015	Power sales are Firm Partial Requirements
~~69.~~	~~Santa Clara (City of)~~	~~Interconnection Agreement - PG&E Rate Schedule FERC No. 85~~	~~Interconnection, transmission, power sales~~	~~10/27/2013, or 3 years notice~~	~~Power sales are Firm Partial Requirements~~
~~70.~~	~~Santa Clara (City of)~~	~~Bulk Power Sales - PG&E Rate Schedule FERC No. 108~~	~~Power sales~~	~~1/1/2002~~	~~Firm Sale 50 MW Sale~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~71.~~	Santa Clara (City of)	Mokelumne Settlement and Grizzly Development Agreement - PG&E ~~Rate Schedule FERC No. 85~~ Service Agreement No. 20 under FERC Electric Tariff Sixth Revised Volume No. 5	Transmission, power sales	1/1/2034~~12/31/2003~~	
~~72.~~	~~SCE~~	~~Service Agreement No. 33 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	#	~~Effective 8/16/97~~
~~73.~~	~~SCE, SDG&E~~	~~California Power Pool - PG&E Rate Schedule FERC No. 27~~	~~Power pool~~	~~Evergreen, or 3 years notice~~	~~Notice of Termination accepted for filing 2/21/97, suspended for 5 months~~
~~74.~~16.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement - PG&E Rate Schedule FERC No. 38	Transmission service	7/31/2007~~4/1/2007~~	Both entitlement and encumbrance.
~~75.~~	~~SCE, SDG&E, Los Angeles Department of Water and Power~~	~~Interconnection and Cooperative Use of Pacific Intertie Facilities Agreement - PG&E Rate Schedule FERC No. 177~~	~~Communication facilities~~	~~7/31/2007, or 23 months notice~~	
~~76.~~17.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan - PG&E Rate Schedule FERC No. 221 ~~183~~	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if we are asked to cut.
~~77.~~	~~SDG&E~~	~~Service Agreement No. 12 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	#	~~Effective 3/24/97~~
~~78.~~	~~Seattle City Light and Power Board~~	~~Interchange Agreement - PG&E Rate Schedule FERC No. 179~~	~~Power exchanges~~	~~Evergreen, or 30 day notice~~	
~~79.~~	~~Shasta Lake (City of)~~	~~Rate Settlement Agreement - PG&E Rate Schedule FERC No. 89~~	~~Power sales~~	~~No notice of termination filed with FERC~~	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~80.~~18.	Shelter Cove	~~Power Sale~~ Interconnection Agreement- PG&E Rate Schedule FERC No. 198 ~~90~~	Distribution	6/30/2006~~Evergreen, or 6 months notice~~	Effective 8/15/96~~Submitted to FERC; docket pending Commission review and clarification and review as of 3/17/97~~
~~81.~~19.	Sierra Pacific	Interconnection Agreement - PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
~~82.~~	~~Sierra pacific Power Company~~	~~Service Agreement No. 32 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 8/15/97~~
~~83.~~20.	SMUD	Interconnection Agreement - PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
~~84.~~	~~SMUD~~	~~Transmission Rate Schedule - PG&E Rate Schedule FERC No. 138~~	~~Transmission~~	~~12/31/99~~	
~~85.~~21.	SMUD	EHV Transmission Agreement - PG&E Rate Schedule FERC No. 37	Transmission	1/1/2005~~, may be subject to dispute~~	
~~86.~~	~~SMUD~~	~~SMUDGEO Transmission Agreement - PG&E Rate Schedule FERC No. 176~~	~~Transmission~~	~~12/31/99~~	
~~87.~~22.	SMUD	Camp Far West Transmission Agreement - PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	
~~88.~~23.	SMUD	Slab Creek Transmission Agreement - PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	
~~89.~~	~~SMUD~~	~~Power Sale Agreement - PG&E Rate Schedule FERC No. 122~~	~~Power sales~~	~~No notice of termination filed with FERC~~	
~~90.~~	~~Southern Energy Trading and Marketing, Inc.~~	~~Service Agreement No. 5 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~#~~	~~Effective 3/12/97~~

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~91.~~	~~Tacoma City Light~~	~~Interchange Agreement - PG&E Rate Schedule FERC No. 58~~	~~Exchange of non-firm electric energy~~	~~Evergreen, or 30 day notice~~	
~~92.~~	~~Tacoma City Light~~	~~Letter Agreement re: provisional energy sale - PG&E Rate Schedule FERC No. 59~~	~~Energy sales~~	~~No notice of termination filed with FERC~~	
~~93.~~24.	(TANC) and other COTP Participants	Coordinated Operations Agreement - PG&E Rate Schedule FERC No. 146	Transmission system coordination, curtailment sharing, rights allocation, scheduling.~~Interconnection, scheduling, transmission~~	1/1/2043, or earlier if other agreements terminate	Establishes relationship of the COTP to the Control Area Operator.~~Both entitlement and encumbrance~~
~~94.~~25.	(TANC) and other COTP Participants	COTP Interconnection Rate Schedule - PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	
~~95.~~26.	TANC	Midway Transmission Service / South of Tesla Principles - PG&E Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation,* replacement power~~-sales~~	~~1/1/2010~~ Same as the COTP Interim Participation Agreement, subject to exception	~~Power sales are voluntary Replacement Power~~
~~96.~~	~~Trinity Public Utility District~~	~~Islanding Agreement - PG&E Rate Schedule FERC No. 79~~	~~Operations~~	~~No notice of termination filed with FERC~~	
~~97.~~	~~Tuolumne County Public Power Agency~~	~~Distribution Services Agreement - PG&E Rate Schedule FERC No. 76~~	~~Distribution~~	~~Evergreen, or 30 day notice~~	
~~98.~~27.	Turlock Irrigation District	Interconnection Agreement - PG&E Rate Schedule FERC No. 213~~115~~	Interconnection, transmission, power sales	4/1/2008, subject to exception	Power Sales are Firm Obligation Sales (Partial Requirements); Contract Firm (Firm Sale requested by TID); and Coordination Sales - Voluntary Spot Sales

* Includes use of PG&E's DC Intertie or PDCI for prespecified mitigation of curtailments over Path 15.

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~99.~~	~~Utility 2000~~	~~Enabling Agreement - PG&E Rate Schedule FERC No.188~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	~~Nonobligatory opportunity sales only~~
~~100.~~	~~Various - See Attachment A~~	~~Western Systems Power Pool Agreement - WSPP Rate Schedule FERC No. 1~~	~~Power sales, transmission~~	~~Upon WSPP expiration~~	~~Both entitlement and encumbrance~~
~~101.~~	~~Various - See Attachment B~~	~~Special facilities agreement~~	~~Provision of special facilities, interconnection related services~~	~~Various~~	~~PG&E has not yet reviewed the applicability of each of the attached agreements, but for the sake of caution, are including them here.~~
~~102.~~28	Vernon (City of)	Transmission Service Exchange Agreement - PG&E Rate Schedule FERC No. 148	Transmission service	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for ~~service on~~ Vernon's COTP rights
~~103.~~29	WAPA	San Luis Unit ~~Pumping~~ - Contract No. 2207A - PG&E Rate Schedule FERC No. 79	Transmission	4/1/2016	
~~104.~~30	WAPA, SCE & SDG&E ~~& CA Companies~~	EHV Transmission Agreement - Contract No. 2947A - PG&E Rate Schedule FERC No.35	Transmission rights, exchange and coordination, and transmission service	1/1/2005, unless extended by agreement of the parties~~may be renewed at negotiated rates.~~	Both entitlement and encumbrance.
~~105.~~31	WAPA	Sale, Interchange and Transmission ~~Agreement~~ - Contract No. 2948A - PG&E Rate Schedule FERC No. 79	Integration, interconnection, transmission and power sales and exchanges	1/1/2005	
~~106.~~32	WAPA	Wintu Pumping Plant - Contract No. 2979A - PG&E Rate Schedule FERC No. 79	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005	
~~107.~~33	WAPA	Delta Pumping Plant - Contract No. DE-AC65-80WP59000 - PG&E Rate Schedule FERC No. 63	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 3 years notice	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~108.~~34	WAPA	Healdsburg, Lompoc & Ukiah - Contract No. DE-MS65-83WP59055 - PG&E Rate Schedule FERC No. 81	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 4 years notice	
~~109.~~35	WAPA	Sonoma County Water Agency - Contract No. 88-SAO-40002 - PG&E Rate Schedule FERC No. 126	Transmission	6/30/94, or concurrent with Contract 2948A expiration of 1/1/2005, or 4 years notice	
~~110.~~36	WAPA	New Melones - Contract No. 8-07-20-P0004 - PG&E Rate Schedule FERC No. 60	Transmission	6/1/2032 ~~"...effective for 50 years beginning on the latter of 1/1/79 or 30 days prior to first unit at New Melones ready to be synchronized with transmission"~~	Per WAPA, commercial operation date for New Melones was 6/1/82
~~111.~~	~~WAPA~~	~~Settlement of Capacity Related Disputes - Contract No. 93-SAO-18003, Supplement No. 41 - PG&E Rate Schedule FERC No. 79~~	~~Power sales~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005~~	
~~112.~~37	WAPA	Trinity County PUD & Lewiston Power Plant ~~Standby Transmission~~ - Contract No. 93-SAO-18008, Supplement No. 42 - PG&E Rate Schedule FERC No. 79	Transmission	1/1/2005	
~~113.~~	~~WAPA~~	~~Capacity Rates/Sales - Contract No. 95-SAO-90007 - PG&E Rate Schedule FERC No. 79~~	~~Capacity sales~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005~~	

Ref. #	Entities	Contract/ Rate Schedule #	Nature of Contract	Termination	Comments
~~114.~~	~~Washington Water Power~~	~~Capacity & Energy Exchange Agreement - PG&E Rate Schedule FERC No. 135~~	~~Power sales~~	~~Evergreen, or 30 day notice~~	
~~115.~~	~~Western Power Services Inc.~~	~~Service Agreement No. 15 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service - OAT~~	~~Upon OAT expiration~~	~~Effective 3/19/97~~
~~116.~~	~~Westlands Irrigation District~~	~~Distribution Service Agreement - PG&E Rate Schedule FERC No. 79~~	~~Local distribution~~	~~Concurrent with Contract No. 2948A expiration of 1/1/2005~~	
~~117.~~	~~Williams Energy Service Company~~	~~Service Agreement No. 9 under FERC Electric Tariff, Original Volume No. 3~~	~~Non-Firm Point-to-Point Transmission Service~~	[1]	~~Effective 3/10/97~~

Lien Mortgage

The lien of the First and Refunding Mortgage dated December 1, 1920 between PG&E and BNY Western Trust Company, as trustee, as amended and supplemented and in effect on the date hereof (the "PG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the PG&E Property which would be prior to the lien of the PG&E Mortgage; however, no consent of the trustee under the PG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

---

[1] ~~In December 1997, PG&E anticipates filing at FERC for termination of all non-firm point-to-point service agreements under OAT. The proposed effective date of termination will be December 31, 1997. Subject to FERC approval these types of service agreements will be terminated.~~

~~ATTACHMENT A~~
~~(to PG&E APPENDIX B)~~

~~Western System Power Pool~~

~~Western System Power Pool Member List~~

~~The Western System Power Pool (WSPP) is a marketing group for the West Coast wholesale power marketers and electric utilities. WSPP membership allows a company to make wholesale power deals under the WSPP master contract.~~

	~~Joined~~	~~Code~~	~~Member~~	~~State~~
~~1~~	~~Apr 96~~	~~AIG~~	~~AIG Trading Corporation~~	~~CT~~
~~2~~	~~Jun 97~~	~~AHE~~	~~American Hunter Energy Inc.~~	~~TX~~
~~3~~	~~Jul 87~~	~~ANHM~~	~~Anaheim, City of, Public Utilities Dept.~~	~~CA~~
~~4~~	~~Feb 96~~	~~APC~~	~~Aquila Power Corporation~~	~~NE~~
~~5~~	~~May 87~~	~~AEPC~~	~~Arizona Electric Power Co.~~	~~AZ~~
~~6~~	~~May 87~~	~~APS~~	~~Arizona Public Service Co.~~	~~AZ~~
~~7~~	~~Nov 94~~	~~AECC~~	~~Arkansas Electric Coop. Corp.~~	~~AR~~
~~8~~	~~Oct 90~~	~~EES~~	~~Arkansas Power & Light~~	~~AR~~
~~9~~	~~Feb 96~~	~~AECI~~	~~Associated Electric Cooperative~~	~~MO~~
~~10~~	~~Jun 97~~	~~AVST~~	~~Avista Energy, Inc.~~	~~WA~~
~~11~~	~~May 87~~	~~BPA~~	~~Bonneville Power Adm.~~	~~OR~~
~~12~~	~~Aug 95~~	~~BURB~~	~~Burbank, City of~~	~~CA~~
~~13~~	~~Jul 92~~	~~CAJN~~	~~Cajun Electric Power Cooperative~~	~~LA~~
~~14~~	~~May 87~~	~~CDWR~~	~~Calif. Dept. of Water Res.~~	~~CA~~
~~15~~	~~Jan 96~~	~~CPSC~~	~~Calpine Power Services Co.~~	~~CA~~
~~16~~	~~Jun 97~~	~~CPLC~~	~~Carolina Power & Light Company~~	~~NC~~
~~17~~	~~Jun 89~~	~~CSWS~~	~~Central & South West Services, Inc..~~	~~TX~~
~~18~~	~~Jul 90~~	~~CLEC~~	~~Central Louisana Electric Co.~~	~~LA~~
~~19~~	~~Jan 96~~	~~CIN~~	~~Cincinnati Gas & Electric~~	~~OH~~
~~20~~	~~Jan 96~~	~~CIN~~	~~CINergy Corporation~~	~~OH~~
~~21~~	~~Dec 95~~	~~CLPS~~	~~Citizens Lehman Power Sales~~	~~MA~~
~~22~~	~~Oct 95~~	~~CLTN~~	~~City of Colton~~	~~CA~~
~~23~~	~~Aug 97~~	~~INDN~~	~~City of Independence~~	~~MO~~
~~24~~	~~Feb 97~~	~~SIKE~~	~~City of Sikeston, Board of Municipal Utilities~~	~~MO~~
~~25~~	~~Nov 90~~	~~CUS~~	~~City Utilities of Springfield~~	~~MO~~
~~26~~	~~Feb 96~~	~~CWL~~	~~City Water & Light (Jonesboro, AR)~~	~~AR~~
~~27~~	~~Aug 97~~	~~CMS~~	~~CMS Marketing, Services and Trading Company~~	~~MI~~
~~28~~	~~Jan 96~~	~~CNG~~	~~CNG Power Services Corp.~~	~~PA~~
~~29~~	~~Aug 95~~	~~CESC~~	~~Coastal Electric Services, TX~~	
~~30~~	~~Jan 97~~	~~CSU~~	~~Colorado Springs Utilities~~	~~CO~~
~~31~~	~~Feb 97~~	~~CAES~~	~~ConAgra Energy Services, Inc.~~	~~NE~~
~~32~~	~~Jun 96~~	~~CORP~~	~~Coral Power, L.L.C.~~	~~TX~~
~~33~~	~~Nov 95~~	~~DESI~~	~~Delhi Energy Services, Inc.~~	~~TX~~
~~34~~	~~Nov 92~~	~~DGT~~	~~Deseret G&T~~	~~UT~~

	~~Joined~~	~~Code~~	~~Member~~	~~State~~
~~35~~	~~Apr 95~~	~~DPS~~	~~Destec Power Services, Inc.~~	~~CA~~
~~36~~	~~Aug 97~~	~~DUKE~~	~~Duke Power~~	~~NC~~
~~37~~	~~Jun 96~~	~~DPMI~~	~~DuPont Power Marketing, Inc.~~	~~TX~~
~~38~~	~~July 96~~	~~EPRM~~	~~e prime, inc~~	~~CO~~
~~39~~	~~Jul 97~~	~~EPDI~~	~~Eastern Power Distribution, Inc.~~	~~VA~~
~~40~~	~~Feb 96~~	~~ETEX~~	~~Eastex Power Marketing, Inc.~~	~~TX~~
~~41~~	~~Nov 96~~	~~ESRC~~	~~Edison Source~~	~~CA~~
~~42~~	~~Nov 94~~	~~EPA~~	~~Edmonton Power Authority~~	~~AB~~
~~43~~	~~Apr 97~~	~~EPE~~	~~El Paso Electric~~	~~TX~~
~~44~~	~~Feb 96~~	~~EPEM~~	~~El Paso Energy Marketing Company~~	~~TX~~
~~45~~	~~Apr 95~~	~~ECI~~	~~Electric Clearing House, Inc.~~	~~TX~~
~~46~~	~~Nov 94~~	~~EDE~~	~~Empire District Electric Co.~~	~~MO~~
~~47~~	~~Aug 95~~	~~CESC~~	~~Engage Energy US, L.P.~~	~~TX~~
~~48~~	~~Aug 95~~	~~ENGL~~	~~Engelhard Power Marketing, Inc.~~	~~NJ~~
~~49~~	~~Nov 94~~	~~EPMI~~	~~Enron Power Marketing, Inc.~~	~~TX~~
~~50~~	~~Feb 97~~	~~EEI~~	~~Enserco Energy Inc.~~	~~CO~~
~~51~~	~~Oct 90~~	~~EES~~	~~Entergy Electric System~~	~~AR~~
~~52~~	~~Jun 96~~	~~EPMC~~	~~Entergy Power Marketing Corp.~~	~~AR~~
~~53~~	~~Nov 94~~	~~EPI~~	~~Entergy Power, Inc.~~	~~AR~~
~~54~~	~~Sep 95~~	~~EPSC~~	~~Equitable Power Services Co.~~	~~TX~~
~~55~~	~~Sep 93~~	~~EWEB~~	~~Eugene Water & Elec. Board~~	~~OR~~
~~56~~	~~Jun 88~~	~~FARM~~	~~Farmington, City of~~	~~NM~~
~~57~~	~~Jun 96~~	~~FESI~~	~~Federal Energy Sales, Inc.~~	~~TX~~
~~58~~	~~Aug 95~~	~~GRDA~~	~~Grand River Dam Authority~~	~~OK~~
~~59~~	~~Oct 90~~	~~EES~~	~~Gulf States Utilities~~	~~TX~~
~~60~~	~~Dec 95~~	~~HES~~	~~Heartland Energy Services~~	~~WI~~
~~61~~	~~Mar 92~~	~~HHWP~~	~~Hetch-Hetchy Water & Power~~	~~CA~~
~~62~~	~~May 97~~	~~HEC~~	~~Howard Energy Co., Inc.~~	~~MI~~
~~63~~	~~Jun 89~~	~~IPC~~	~~Idaho Power Company~~	~~ID~~
~~64~~	~~Aug 95~~	~~IPMI~~	~~Illinova Power Marketing, Inc.~~	~~UT~~
~~65~~	~~Jan 92~~	~~IID~~	~~Imperial Irrigation District~~	~~CA~~
~~66~~	~~May 96~~	~~IEA~~	~~Industrial Energy Applications~~	~~IA~~
~~67~~	~~Jul 96~~	~~IPM~~	~~InterCoast Power Marketing~~	~~IA~~
~~68~~	~~Feb 96~~	~~JAC~~	~~J. Aron & Company~~	~~NY~~
~~69~~	~~May 97~~	~~KAMO~~	~~KAMO Electric Cooperative, Inc.~~	~~OK~~
~~70~~	~~Jan 94~~	~~KCPL~~	~~Kansas City Power & Light~~	~~MO~~
~~71~~	~~Feb 96~~	~~KNM~~	~~KN Energy Marketing.~~	~~TX~~
~~72~~	~~Aug 95~~	~~KETI~~	~~Koch Energy Trading, Inc.~~	~~TX~~
~~73~~	~~Mar 88~~	~~LDWP~~	~~LA Dept. of Water & Power~~	~~CA~~
~~74~~	~~Apr 95~~	~~LEM~~	~~LG&E Energy Marketing Inc.~~	~~CA~~
~~75~~	~~Mar 96~~	~~LES~~	~~Lincoln Electric System~~	~~NE~~
~~76~~	~~Jul 92~~	~~LAC~~	~~Los Alamos County~~	~~NM~~
~~77~~	~~Sep 93~~	~~LDEP~~	~~Louis Dreyfus Elec. Power, Inc.~~	~~AZ~~
~~78~~	~~Oct 90~~	~~EES~~	~~Louisiana Power & Light~~	~~LA~~
~~79~~	~~Aug 96~~	~~LGE~~	~~Louisville Gas & Electric Co.~~	~~KY~~
~~80~~	~~Apr 97~~	~~MW&L~~	~~McMinnville Water & Light~~	~~OR~~
~~81~~	~~Dec 90~~	~~MWD~~	~~Metropolitan Water District~~	~~CA~~
~~82~~	~~Apr 96~~	~~MEC~~	~~MidAmerican Energy Company~~	~~IA~~

	~~Joined~~	~~Code~~	~~Member~~	~~State~~
~~83~~	~~Jul-97~~	~~MPS~~	~~MidCon Power Services Corp.~~	~~IL~~
~~84~~	~~Oct-90~~	~~EES~~	~~Mississippi Power & Light~~	~~MS~~
~~85~~	~~Aug-95~~	~~MOCK~~	~~Mock Energy Services, L.P.~~	~~CA~~
~~86~~	~~Jun-89~~	~~MID~~	~~Modesto Irrigation District~~	~~CA~~
~~87~~	~~Jun-87~~	~~MPC~~	~~Montana Power Co.~~	~~MT~~
~~88~~	~~Dec-95~~	~~MSCG~~	~~Morgan Stanley Capital Group, Inc.~~	~~NY~~
~~89~~	~~May-95~~	~~MSR~~	~~M-S-R Public Power Agency~~	~~CA~~
~~90~~	~~Dec-95~~	~~MEAM~~	~~Municipal Energy Agency of MS~~	~~MS~~
~~91~~	~~Jan-96~~	~~NGE~~	~~National Gas & Electric L.P.~~	~~TX~~
~~92~~	~~Mar-96~~	~~NPPD~~	~~Nebraska Public Power District~~	~~NE~~
~~93~~	~~May-87~~	~~NEVP~~	~~Nevada Power Co.~~	~~NV~~
~~94~~	~~Oct-90~~	~~EES~~	~~New Orleans Public Services~~	~~LA~~
~~95~~	~~Aug-95~~	~~NES~~	~~NorAm Energy Services, Inc.~~	~~TX~~
~~96~~	~~May-87~~	~~NCPA~~	~~Northern Calif Power Agency~~	~~CA~~
~~97~~	~~May-97~~	~~NPEI~~	~~NP Energy Inc.~~	~~KY~~
~~98~~	~~Dec-92~~	~~OGE~~	~~Oklahoma Gas & Electric~~	~~OK~~
~~99~~	~~May-96~~	~~OPPD~~	~~Omaha Public Power District~~	~~NE~~
~~100~~	~~May-87~~	~~PG&E~~	~~Pacific Gas & Electric Co.~~	~~CA~~
~~101~~	~~Feb-97~~	~~PNGC~~	~~Pacific Northwest Generating Cooperative~~	~~OR~~
~~102~~	~~May-87~~	~~PAC~~	~~PacifiCorp~~	~~OR~~
~~103~~	~~May-95~~	~~PPSI~~	~~PanEnergy Power Services, Inc.~~	~~WA~~
~~104~~	~~Nov-94~~	~~PASA~~	~~Pasadena, City of~~	~~CA~~
~~105~~	~~Mar-96~~	~~PECO~~	~~PECO Energy Company~~	~~PA~~
~~106~~	~~Jun-97~~	~~PPL~~	~~Pennsylvania Power & Light Co.~~	~~PA~~
~~107~~	~~Oct-96~~	~~PGES~~	~~PG&E Energy Services, Energy Trading Corp.~~	~~CA~~
~~108~~	~~Nov-95~~	~~PGPS~~	~~PG&E Power Services Company~~	~~TX~~
~~109~~	~~May-96~~	~~PHB~~	~~Phibro, Inc.~~	~~CT~~
~~110~~	~~Sep-93~~	~~PEGT~~	~~Plains Elec Gen & Trans Coop~~	~~NM~~
~~111~~	~~May-96~~	~~PRPA~~	~~Platte River Power Authority~~	~~CO~~
~~112~~	~~May-87~~	~~PGE~~	~~Portland General Elec. Co.~~	~~OR~~
~~113~~	~~Jan-97~~	~~PCA~~	~~Power Company of America, L.P.~~	~~CT~~
~~114~~	~~May-95~~	~~PXC~~	~~Power Exchange Corporation~~	~~CA~~
~~115~~	~~Jun-89~~	~~PWX~~	~~Powerex~~	~~BC~~
~~116~~	~~May-87~~	~~PNM~~	~~Public Service Co. of NM~~	~~NM~~
~~117~~	~~Jun-89~~	~~CSWS~~	~~Public Service Co. of Oklahoma~~	~~OK~~
~~118~~	~~Jan-96~~	~~CIN~~	~~Public Service of Indiana~~	~~IN~~
~~119~~	~~Sep-93~~	~~PSC~~	~~Public Svc Co of Colorado~~	~~CO~~
~~120~~	~~Nov-94~~	~~CHPD~~	~~PUD No. 1 of Chelan County~~	~~WA~~
~~121~~	~~May-95~~	~~GHPD~~	~~PUD No. 1 of Grays Harbor~~	~~WA~~
~~122~~	~~Jul-95~~	~~SNPD~~	~~PUD No. 1 of Snohomish County~~	~~WA~~
~~123~~	~~Sep-95~~	~~GCPD~~	~~PUD No. 2 of Grant County~~	~~WA~~
~~124~~	~~Jun-87~~	~~PSPL~~	~~Puget Sound Power & Light Co.~~	~~WA~~
~~125~~	~~Aug-97~~	~~QST~~	~~QST Energy Trading Inc.~~	~~TX~~
~~126~~	~~Sep-96~~	~~QET~~	~~Questar Energy Trading~~	~~UT~~
~~127~~	~~Apr-96~~	~~REMC~~	~~Rainbow Energy Marketing Corp.~~	~~ND~~
~~128~~	~~Nov-94~~	~~REDD~~	~~Redding, City of~~	~~CA~~
~~129~~	~~Jul-87~~	~~RVSD~~	~~Riverside of California~~	~~CA~~

	Joined	Code	Member	State
~~130~~	~~Jul-87~~	~~RMGC~~	~~Rocky Mountain Gen. Coop., Inc.~~	~~CO~~
~~131~~	~~May-87~~	~~SMUD~~	~~Sacramento Municipal Utility Dist~~	~~CA~~
~~132~~	~~May-87~~	~~SRP~~	~~Salt River Project~~	~~AZ~~
~~133~~	~~May-87~~	~~SDGE~~	~~San Diego Gas & Electric Co.~~	~~CA~~
~~134~~	~~Sep-90~~	~~SNCL~~	~~Santa Clara, City of, Electric Dept.~~	~~CA~~
~~135~~	~~May-96~~	~~SCPS~~	~~Santee Cooper~~	~~SC~~
~~136~~	~~May-93~~	~~SCL~~	~~Seattle City Light~~	~~WA~~
~~137~~	~~Jun-87~~	~~SPP~~	~~Sierra Pacific Power Co.~~	~~NV~~
~~138~~	~~Feb-96~~	~~SPM~~	~~Sonat Power Marketing~~	~~AL~~
~~139~~	~~May-87~~	~~SCE~~	~~Southern Calif. Edison Co.~~	~~CA~~
~~140~~	~~Oct-97~~	~~SOCO~~	~~Southern Company Services, Inc.~~	~~AL~~
~~141~~	~~Dec-95~~	~~SETM~~	~~Southern Energy Trading & Marketing, Inc.~~	~~GA~~
~~142~~	~~Feb-97~~	~~SWPA~~	~~Southwest Power Administration~~	~~OK~~
~~143~~	~~Jun-89~~	~~CSWS~~	~~Southwestern Electric Power Co.~~	~~LA~~
~~144~~	~~Jun-87~~	~~SPS~~	~~Southwestern Public Svc.~~	~~TX~~
~~145~~	~~May-95~~	~~SJLP~~	~~St. Joseph Light & Power Co.~~	~~MO~~
~~146~~	~~Jun-95~~	~~SEPC~~	~~Sunflower Electric Power Corp.~~	~~KS~~
~~147~~	~~Oct-97~~	~~TCL~~	~~Tacoma City Light~~	~~WA~~
~~148~~	~~May-97~~	~~TNSK~~	~~Tenaska Power Services Co.~~	~~TX~~
~~149~~	~~Jan-96~~	~~TEMC~~	~~Tenneco Energy Marketing Co.~~	~~TX~~
~~150~~	~~Dec-95~~	~~TVA~~	~~Tennessee Valley Authority~~	~~TN~~
~~151~~	~~May-97~~	~~TEMI~~	~~Tractebel Energy Marketing, Inc.~~	~~TX~~
~~152~~	~~Jul-96~~	~~TEM~~	~~TransAlta Energy Marketing~~	~~AB~~
~~153~~	~~Jul-96~~	~~TCPC~~	~~TransCanada Power Corp.~~	~~AB~~
~~154~~	~~Jul-90~~	~~TEP~~	~~Tucson Electric Power~~	~~AZ~~
~~155~~	~~Sep-90~~	~~TID~~	~~Turlock Irrigation District~~	~~CA~~
~~156~~	~~Dec-95~~	~~UEC~~	~~Union Electric~~	~~MO~~
~~157~~	~~Apr-96~~	~~USPS~~	~~USGEN Power Services~~	~~MD~~
~~158~~	~~Apr-93~~	~~UAMP~~	~~Utah Assoc Muni Pwr Systems~~	~~UT~~
~~159~~	~~Sep-93~~	~~UGK~~	~~UtiliCorp Energy Group, Kansas~~	~~KS~~
~~160~~	~~Jan-95~~	~~UGM~~	~~UtiliCorp Energy Group, Missouri~~	~~MO~~
~~161~~	~~Oct-96~~	~~VPM~~	~~Vastar Power Marketing, Inc.~~	~~TX~~
~~162~~	~~Mar-94~~	~~VERN~~	~~Vernon, City of~~	~~CA~~
~~163~~	~~Jan-97~~	~~VAP~~	~~Virginia Electric and Power Company~~	~~VA~~
~~164~~	~~Jan-96~~	~~VGE~~	~~Vitol Gas & Electric, L.L.C.~~	~~MA~~
~~165~~	~~Dec-91~~	~~WWPC~~	~~Washington Water Power~~	~~WA~~
~~166~~	~~Nov-94~~	~~WKPL~~	~~West Kootenay Power~~	~~BC~~
~~167~~	~~Jun-89~~	~~WALC~~	~~Western Adm. Lower Colorado~~	~~AZ~~
~~168~~	~~Feb-94~~	~~WAMP~~	~~Western Adm. Sacramento~~	~~CA~~
~~169~~	~~Jun-89~~	~~WAUC~~	~~Western Adm. Upper Colorado~~	~~UT~~
~~170~~	~~Jul-96~~	~~WAUP~~	~~Western Adm. Upper Great Plains~~	~~SD~~
~~171~~	~~Aug-95~~	~~WFEC~~	~~Western Farmers Electric Co-op~~	~~OK~~
~~172~~	~~Dec-95~~	~~WPS~~	~~Western Power Svcs, Inc.~~	~~CO~~
~~173~~	~~Feb-94~~	~~WRI~~	~~Western Resources, Inc.~~	~~KS~~
~~174~~	~~Mar-96~~	~~WESC~~	~~Williams Energy Services Company~~	~~OK~~
~~175~~	~~Apr-97~~	~~*~~	~~MP Energy~~	~~*~~

~~* Data not available, information provided from CIPS, FERC's Electronic Bulletin Board.~~
~~All other information provided from:~~
~~http:/www.EnergyOnLine.com/Restructuring/players/marketers/wspp4.html~~

EXHIBIT B-1
(TO PG&E APPENDIX B)

Path 15 Operating Instructions
For Existing Encumbrances Across the Path 15 Interface
January 19, 1999

Introduction

As contemplated by the ISO Tariff, and as directed by the Federal Energy Regulatory Commission in its orders on Amendments 3 and 7 to the ISO Tariff, which were filed by the ISO, Pacific Gas and Electric Company (PG&E) has worked with the parties with whom it has existing contracts for transmission service over Path 15 (ETC Parties), in order to develop these Operating Instructions, which, pursuant to sections 2.4.3.1, 2.4.4.4.1, and 2.4.4.4.3 of the ISO Tariff, are to be followed by the ISO in operating this constrained Path. The constraints on Path 15 have been known by all transmission users for many years and have not been alleviated by the creation or operation of the ISO. The Operating Instructions which follow are intended to preserve each ETC Party's pre-existing contract rights to transmission service over Path 15 and PG&E's use of that transmission path. These Operating Instructions will remain in place until the earlier of (a) April 1, 2003 or (b) the expiration of the Regulatory Must-Take status of PG&E's Diablo Canyon Nuclear Power Plant. Unless otherwise mutually agreed by all parties, these Operating Instructions will be in effect for this interim period, only, and all parties reserve all rights to argue for the implementation of different Operating Instructions and priorities for Path 15 consistent with their ETC contract rights, following this interim period. Further, any party may oppose any modification of these Operating Instructions that materially affects the rights of such party as set forth herein.

Purpose and Objectives

These Path 15 Operating Instructions provide direction to the ISO regarding the management of congestion on Path 15 during the ISO's Day Ahead, Hour Ahead and Real Time markets. The objective of these instructions is to assure, on an ongoing basis, the efficient use each day of available Path 15 transfer capability while maintaining the transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date. These instructions also clarify individual and joint responsibilities between the ISO as the Control Area Operator and PG&E as the Path 15 Existing Transmission Contract (ETC) Facilitator.[1/]

[1/] Specific operating instructions have been provided to the ISO by PG&E in other documents for each of the Existing Contracts for which it is the Responsible Participating Transmission Owner on Path 15. In the contract specific instructions, information is provided on the maximum MW of transmission service available over the path; the quality of transmission service; daily, hourly and real time scheduling rights and responsibilities; curtailment procedures; points of receipt and points of delivery and effective and termination dates of the contract. This set of additional instructions will clarify how the relative

These instructions are to be adhered to except when the ISO determines that system reliability requires that other steps be taken. The ISO is solely responsible for continued system reliability and must unilaterally take all steps necessary to preserve the system in times of emergency.

Path 15 Existing Transmission Contract Facilitator (ETC Facilitator)

PG&E will serve in the capacity of ETC Facilitator to assist the ISO and to provide necessary guidance to the ISO in the administration of Path 15 ETC rights. The ETC Facilitator shall:

1. Provide to the ISO for each hour of the Trading Day, the total amount of megawatts that should be reserved for use by the ETC Parties.[2/] Such amounts shall be provided generally by 8:30 a.m. of each weekday prior to the start of a Trading Day for the Day-Ahead Market, and generally by 4:30 p.m. of the weekday prior to the start of a Trading Day for the Hour-Ahead Market.[3]

2. Facilitate all Path 15 schedules from ETC Parties, including those ETC Parties for which the ETC Facilitator is not the Scheduling Coordinator (SC).

3. Schedule all SC to SC transfers[4/] that utilize ETC rights across Path 15.

4. Inform ETC Parties, affected SCs, and the ISO, pursuant to these Operating Instructions, when an ETC Party's scheduled usage of Path 15 is reduced and the amount of such reduction.

5. In performing these tasks, ensure that all transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date are maintained and protected.

---

transmission rights and priorities of the parties should be managed and administered during times of congestion and possible curtailment on Path 15.

2/ The ETC Facilitator's specification of the megawatt reservation amount does not limit, in any way, ETC Parties' ability to exercise their rights, including making schedule changes in real time.

3/ PG&E and most of the ETC Parties pre-schedule Monday through Friday only. PG&E generally provides its ETC reservation for Sunday and Monday by close-of-business on Friday and to the extent practicable, encourages ETC Parties to provide pre-schedules in time to meet the ISO's Day-Ahead market deadline.

4/ Currently, Southern California Edison Company (Edison) schedules its SC-SC transfers for its Existing Contracts directly with the ISO. Upon mutual agreement by Edison and PG&E, PG&E may become a party to these SC-SC transfers across Path 15.

Day-Ahead Market Congestion Management

Prior to the start of the ISO Day-Ahead process, the ETC Facilitator will provide the ISO with an hourly reservation for ETC schedules utilizing Path 15. The ISO will determine the hourly amount of the Path 15 operating limit available for New Firm Uses[5/] for use in its Congestion Management Process[6/] by subtracting the ETC megawatt reservation amount from the operating limit for Path 15 for each hour. After the deadline for receiving Day-Ahead Preferred Schedules, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for each hour of congestion on Path 15. ETC schedules over Path 15 will not be assessed Usage Charges.

Hour-Ahead Market Congestion Management

Because scheduling timelines in ETC Parties' contracts (including third party contracts using ETC Party rights) differ from the ISO's scheduling timeline, some pre-schedules from such parties are likely to be scheduled in the Hour-Ahead Market. The ETC Facilitator's ETC megawatt reservation amount submitted in the Day-Ahead Market is intended to provide sufficient reservation to accommodate the schedules submitted in the Hour-Ahead Market. After the close of the Hour-Ahead Preferred Market, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for such hour on Path 15. ETC schedules over Path 15 will not be assessed Usage Charges.

Real Time Curtailment Priorities

Any and all ETC Parties' rights (including third party contracts using ETC Party rights) to change schedules after the close of the ISO's Hour-Ahead market will continue to be honored. In the event of curtailments on Path 15 South-to-North in real time, the ETC Facilitator will determine the appropriate order and magnitude of curtailments given the circumstances that occur in real time and the terms and provisions of the ETCs. This determination will be made consistent with the following table "Path 15 South-to-North Real-Time Curtailment Priorities", a copy of which is Attachment A, which is incorporated into and made a part of these Path 15 Operating Instructions by this reference.

In Attachment A, the relative priorities of the various ETC Parties' transmission service rights across Path 15 in real-time are identified by grouping the various rights into

---

5/ Regulatory Must Take and Regulatory Must Run resources that contribute to the "imputed use" of Path 15 are treated as New Firm Uses for this purpose. The "imputed use" is the expected power flow resulting from the load, interchange, and resource schedules of all SCs.

6/ The ISO's Congestion Management Process uses Adjustment Bids to reduce the amount of New Firm Use, if necessary, so that such use does not exceed the amount of the Path 15 operating limit less the ETC reservation megawatt amount.

separate blocks and ordering the blocks by their relative priority. Attachment A addresses only Path 15 South to North real-time curtailment priorities. The Path 15 North-to-South real-time curtailment priorities will be addressed in a separate and distinct set of Operating Instructions and will be separately submitted to the ISO after review by the Path 15 ETC Parties.

EXHIBIT B-1 **ATTACHMENT A**
(TO PG&E APPENDIX B)

Path 15 Real-Time South-to-North Curtailment Priorities [1/]

Priority Group	ETC/Priority Holder	South-to-North
1 [2/]	CDWR EHV Agreement [3/] SCE CCPIA encumbered rights [4/] SDG&E CCPIA encumbered rights [5/] PG&E must-take encumbrances CDWR Comprehensive Agreement	300 MW up to 667 MW 0 [6/] 810 MW
2	TANC SOTP [7/]	300 MW
3 [8/]	SMUD TRS (Reserve rights) TID IA (Reserve rights)	400 MW 32 MW
4	Other Encumbrances	189.5 MW [9/]
5 [10/]	PG&E SOTP SCE CCPIA unencumbered rights ' SDG&E CCPIA unencumbered rights '	500 MW varies monthly 109 MW
6	New ETC Requests [11/] Other "As Available"	unspecified

1/ This table may change from time to time as existing contracts are terminated, or the rights under those contracts change (e.g., termination of a QF contract).

2/ Curtailments within Priority Group 1 are pro rata based on each party's contract right or entitlement amount.

3/ CDWR has both EHV and Comprehensive Agreement rights. When curtailments are required, CDWR's EHV schedules are curtailed beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).

4/ Some of SCE's CCPIA rights have been or may be converted for ISO use. When curtailments are required, schedules using these rights are curtailed in accordance with previously established monthly maximum usage levels as agreed upon by SCE and PG&E.

5/ All of SDG&E's CCPIA rights have been converted for ISO use.

6/ The Priority Group 1 capacity available to PG&E south-to-north in real time is the capacity remaining after CDWR's EHV and SCE/SDG&E's CCPIA Existing Contract schedules (as may be curtailed) are subtracted from the amount of available capacity. This remaining capacity is available for CDWR's Comprehensive Agreement schedules and PG&E's must-take encumbrances. PG&E's must-take encumbrances rights correspond to the amount of Path 15 south-to-north transfer capability historically available for PG&E must-take generation in SP 15, including but not limited to the generation of PG&E's Diablo Canyon Nuclear Power Plant, minus PG&E load in SP15. As used in this footnote, "PG&E's must-take encumbrances" means an amount of transmission transfer capability that is reserved for ISO New Firm Uses across Path 15 south-to-north that is the lesser of PG&E's must-take encumbrances rights defined above and the PX imputed use of Path 15. The PX imputed use of Path

15 is the expected power flow resulting from the load, interchange and resource schedules of the PX across Path 15. CDWR's Comprehensive Agreement schedules are curtailed, pro rata with the Priority Group 1 capacity available to PG&E, beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).

7/ TANC's 300 MW is firm bi-directional service using the Points of Receipt and Delivery set forth in section 2.4 of the SOTP and in accordance with the Curtailment Priorities set forth in section 3.2 of the SOTP. PG&E supports these transfer capabilities by implementing mitigation measures when necessary, to the extent such measures are available, up to a total of 200 MW south-to-north and 700 MW north-to-south. These mitigation measures consist of switching PG&E's scheduled transmission service from the AC Lines to the DC Line.

8/ Curtailments within Priority Group 3 are pro rata based on the MW amount of each party's rights.

9/ Priority Group 4 status is available, south-to-north, for only 189.5 MW. Any increases in south-to-north rights under ETCs in Priority Group 4 are designated as "New ETC Requests" and will have Priority Group 6 status.

10/ Priority Group 5 is available for ISO use for New Firm Uses.

11/ "New ETC Requests" includes any requested service by an ETC in excess of the rights set forth in this table for Priority Groups 1-5, provided that this footnote shall not apply to arrangements between or among PG&E and one or more ETC Parties for future capacity upgrades, if such parties agree, or an existing contractual commitment provides otherwise.

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES

	POINT OF RECEIPT	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
1.	Devers - Mirage / Coachella 230 kV	IID	SCE to IID	Firm Transmission Service Agreement	268	On 3-year notice	100 MW May-October, 50 MW rest of the year.
2.	Devers - Banning ISO Grid Take Out Point serving Banning	Banning	Bi-dir	Pasadena Firm Transmission Service	~~248.3~~ 8382	Earlier of 12/31/03 or upon Banning's 1-year notice given after 1/1/02.	10 MW until 10/31/98, 5 MW beginning 1/1/99
3.	Devers - ISO Grid Take Out Point serving Banning	Banning	To Banning	1995 San Juan Unit 3 Firm Transmission Service Agreement	~~248.2~~ 9381	Earlier of termination of Banning's interest in San Juan Unit 3 or Banning's 1-year notice given after 1/1/03	15 MW
4.	Devers– Vista	Colton	To Vista	1995 San Juan Unit 3 Firm Transmission Service Agreement	~~249.2~~ 9265	Earlier of termination of Colton's interest in San Juan Unit 3 or Colton's 1-year notice given after 1/1/03	14.043 MW
5.	Hinds - Vincent	MWD	Bi-dir.	District-Edison 1987 Service and Interchange Agreement	203	9/30/2017 or five-year notice	110 MW
6.	Etiwanda - Vincent	MWD	to Vincent	Amended and Restated District Etiwanda Power Plant Transmission Service Agreement	292 First Revised	Earliest of termination MWD-PG&E Sale Contract, termination of PG&E-CDWR Exchange Contract, termination of SCE-CDWR Power Contract, termination of Interconnection Facilities Agreement, or April 1, 2014. As of the date of this document, this agreement is expected to terminate 12/31/04, which is the date the CDWR Power Contract is expected to terminate.	24 MW
7.	Eldorado-Vincent	CDWR	Bi-dir.	Amended and Restated Firm Transmission Service Agreement (Eldorado-Vincent)	113 First Revised	Earlier of date that a) CDWR has obtained for replacement transmission service; b) CDWR is no longer entitled to Reid Gardner Unit 4 output; c) 12/31/2020; or, d) Reid Gardner Unit 4 is permanently retired from service. ~~replacement facilities are in service, term. Of CDWR Purchase Agreement, retirement of Reid Gardner~~	235 MW

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

~~No. 4, or 12/31/20~~

Footnotes:
1. The following is an additional encumbrance that does not fit into the format for existing contract encumbrances. The additional encumbrance is: The lien of the Trust Indenture dated as of October 1, 1923, between Edison and Harris Trust and Savings Bank and Pacific-Southwest Trust & Savings Bank (D. G. Donovan, successor trustee), as trustees ("the Edison Indenture"). The transfer of control to the ISO pursuant to this Agreement (i) does not require any consent from the trustees under the Edison Indenture, (ii) shall not be deemed to create any lien or charge on the Edison Transmission Assets that would be prior to the lien of the Edison Indenture, and (iii) shall not otherwise impair the lien of the Edison Indenture.
2. The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

	POINT OF RECEIPT / DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
8.	Eldorado / Mohave - Lugo	LADWP	Bi-dir.	Victorville - Lugo Interconnection Agreement	51	2019 or sooner by mutual agreement	Edison is required to provide capacity to LADWP equal to the product of LA's Capacity Share and the deemed capacity of the transmission system consisting of Mohave-Lugo, Mohave-Eldorado, Eldorado-Lugo, Eldorado-McCullough, McCullough-Victorville lines, and Victorville-Lugo 500 kV transmission lines.
9.	Moenkopi - Eldorado	USA, APS, SRP, NPC, LADWP, TGE	Bi-dir.	Edison - Navajo Transmission Agreement	264	5/21/23	In the event of a contingency in the Navajo-McCullough or Moenkopi-Eldorado transmission lines, Edison and the Navajo participants provide each other emergency service transmission rights without a charge.
10.	Mohave - Eldorado	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425~~N/A~~	7/1/06	If Mohave-Eldorado line is curtailed, pro-rata back up is provided on Mohave-Lugo and Eldorado-Lugo lines. If Mohave-Lugo is curtailed, pro-rata back-up is provided on Mohave-Eldorado. Amount of back up capacity is up to participant's Mohave Capacity Entitlement. For curtailment ~~share.~~ purposes, Capacity Entitlements ~~Pro-rata percentages are~~: Edison-884 MW; ~~56%,~~ LADWP-316 MW; ~~20%,~~ NPC-222 MW; ~~14%,~~ SRP-158 MW~~10%~~.

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

11.	Eldorado - Mead	LADWP, NPC, SRP	to Eldorado	Amended and Restated Eldorado System Conveyance and Co-Tenancy Agreement, Eldorado System Conveyance 2 and Co-Tenancy Agreement, Amended and Restated Eldorado System Operating Agreement	424, 425~~N/A~~	7/1/06	If Eldorado-Mead lines are curtailed, line capacity is allocated pro rata in proportion to the following Capacity Entitlements ~~prorated based on following percentages: Edison-70%,~~ NPC-222 MW; ~~17.5%,~~ SRP-158 MW; ~~12.5%~~ LADWP – 0 MW; Edison Capacity Entitlement is equal to entire capacity of the Eldorado-Mead Line Nos. 1&2 minus NPC Capacity Entitlement minus SRP Capacity Entitlement.
12.	Mead - Mohave	NPC	to Mohave	Amended and Restated Agreement for Additional NPC Connection to Mohave Project	426~~N/A~~	Co-terminous with Mohave Project Plant Site Conveyance and Co-Tenancy Agreement	Up to 222 MW of Back-up transmission service.
~~13.~~	~~Four Corners 345kV - Mead~~	~~Anaheim~~	~~to Mead~~	~~Four Corners-Mead Firm Transmission Service Agreement~~	~~Pending~~	~~Earlier of 12/31/02, or 1 year notice, except termination not prior to 12/31/01~~	~~100 MW for June-September, 1998; 50 MW beginning 1/1/99.~~

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT / DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
13 ~~4.~~	Mead - ISO Grid Take Out Point serving Banning	Banning	E-W	Hoover Firm Transmission Service Agreement	378~~248.5~~	Earliest of: agreement to terminate, or date in a Banning 1-year notice given after 1/1/02, or termination of WAPA Service Contract	2 MW
14 ~~5.~~	Mead - Rio Hondo	Azusa	E-W	Sylmar Firm Transmission Service Agreement	375~~247.24~~	Earliest of: agreement to terminate, or ~~Banning's~~ Azusa's 1-year notice given after 1/1/02, or termination of ~~Banning's~~ Azusa's interest in San Juan #3	8 MW
15 ~~6.~~	Mead - Rio Hondo	Azusa	E-W	Hoover Firm Transmission Service Agreement	372~~247.4~~	Earliest of: agreement to terminate, or date in an ~~Banning~~ Azusa 1-year notice given after 1/1/02, or termination of WAPA Service Contract	4 MW
16 ~~7.~~	Mead - Vista	Colton	E-W	Hoover Firm Transmission Service Agreement	361~~249.4~~	Earliest of: agreement to terminate, or date in a Colton 1-year notice given after 1/1/02, or termination of WAPA Service Contract	3 MW
17 ~~8.~~	Mead - Riverside	Riverside	E-W	Hoover Firm Transmission Service Agreement	389~~250.6.12~~	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~Earliest of: agreement to terminate, or termination of 1990 IOA, or termination of WAPA Service Contract~~	30 MW
18 ~~9.~~	Mead - Laguna Bell	Vernon	Bi-dir	Mead Firm Transmission Service Agreement	207	Earlier of agreement to terminate or termination of Hoover Power Sales Agreement	26 MW
19 ~~20.~~	Mead - Mountain Center	AEPCO	E-W	Firm Transmission Service Agreement	131	7/1/21 or on 10 years notice	10 MW

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	~~POINT OF RECEIPT / DELIVERY~~	PARTIES	DIR.	CONTRACT TITLE	FERC NO.	CONTRACT TERMINATION	CONTRACT AMOUNT
20 ~~1.~~	Palo Verde - Devers	LADWP	Bi-dir.	Exchange Agreement	219	Earliest of construction of DPV#2, or removal of DPV1 from service, or transfer of DPV#2 rights of way to LADWP.	368 MW
21 ~~2.~~	Palo Verde - Sylmar	LADWP	Bi-dir.	Exchange Agreement	219	5/31/2012	100 MW
22 ~~3.~~	Sylmar - Devers	LADWP	Bi-dir	Excahnge Agreement	219	When DPV#1 is removed from service, or if DPV#2 is built, the date DPV#2 is removed from service.	368 MW
~~24.~~	~~Palo Verde - COB~~	~~PacifiCorp~~	~~E-W~~	~~Transmission Service Agreement.~~	~~275~~	~~7/31/07~~	~~260 MW during off-peak period.~~
23 ~~5.~~	Palo Verde - Devers Devers - Valley Valley - Serrano Serrano - SONGS	IID, APS, SDG&E	Bi-Dir.	Mutual Assistance Transmission Agreement	174	On 2034 or sooner by agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in an operating bulletin.

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT/ DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
24 ~~6.~~	Midway - Vincent 500 kV	PG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	633 MW
25 ~~7.~~	Midway - SONGS	SDG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	161 MW
26 ~~8.~~	Midway - Vincent 500 kV	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25	320 MW
27 ~~9.~~	Midway - Vincent 500 kV	CDWR	Bi-dir.	Amended and Restated Power Contract	112 First Revised	12/31/04	235 MW
28 ~~30.~~	Midway - Vincent 500 kV	PG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	655 MW
29 ~~31.~~	Midway - SONGS	SDG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	109 MW
30 ~~2.~~	Midway - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement, or 12/29/42 (50 yrs).	60 MW until 1/1/00, 60MW after 12/31/07
31 ~~3.~~	~~Midway - Vincent~~ COB - Tesla 500 kV	SMUD	Bi-dir.~~S-N~~	Contract between California Companies and Sacramento Municipal Utility District for Extra High Voltage Transmission and Exchange Service	39	Useful life of existing Pacific Intertie per Amendment #2	200 MW

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
32 ~~4.~~	Pacific AC 500 kV Intertie	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25	320 MW
33 ~~5.~~	COB-Sylmar - Rio Hondo	Azusa	To Sylmar and Rio Hondo	Pacific Intertie Firm Transmission Service	377~~Pending~~	Earlier of 10/31/03, or upon Azusa's 1-year notice given after 1/1/02	28 MW May-October of 1998, 15 MW May-October thereafter
34 ~~6.~~	COB - Sylmar	Banning	To Sylmar	Pacific Intertie Firm Transmission Service	383.1~~Pending~~	Earlier of 10/31/03, or upon Banning's 1-year notice given after 1/1/02	10 MW May-October of 1998, 5 MW May-October thereafter
35 ~~7.~~	COB - Sylmar-Vista	Colton	To Sylmar and Vista	Pacific Intertie Firm Transmission Service	366~~Pending~~	Earlier of 10/31/03, or upon Colton's 1-year notice given after 1/1/02	15 MW May-October
~~38.~~	~~Pacific DC +/- 500 kV Intertie~~	~~Riverside, BPA~~	~~N-S~~	~~Supplement for the Integration of the 1996 BPA Diversity Exchange.~~	~~250.4~~	~~Midnight 04/30/2016~~	~~50 MW Jan-May, 60 MW June-Dec.~~
~~39.~~	~~SONGS - Lewis~~	~~Anaheim~~	~~To Lewis~~	~~SONGS Firm Transmission Service Agreement~~	~~246.13~~	~~Earliest of: 12/31/02, or agreement to terminate, or 1-year notice, except service will not terminate prior to 12/31/01.~~	~~70 MW.~~
36 ~~40.~~	SONGS - Vista	Riverside	To Vista	SONGS 2 & 3 Firm Transmission Service Agreement	393~~250.15.1~~ 2	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~Termination of SONGS Supplemental or 1990 IOA~~	~~38.798~~42 MW (per 1997 Edison – Riverside Restructuring Agreement).

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	[illegible] DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
37 ~~41~~.	Victorville/Lugo - Midway	MSR	Bi-dir.	Amended and Restated Firm Transmission Service Agreement (Victorville/Lugo-Midway)	339 First Revised	Earlier of: five-year notice by MSR, or life of Mead-Adelanto 500 kV Transmission Project	150 MW
38 ~~42~~.	Victorville/Lugo - Vista	Riverside	To Vista	Intermountain Power Project Firm Transmission Service Agreement	391~~250.8.10~~	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~Earlier of: agreement to terminate, or termination of 1990 IOA, IPP PSA, SCPPA STS Contract, or LADWP IPP Base Capacity Agreement.~~	~~121.638~~ 156 MW (per 1997 Edison – Riverside Restructuring Agreement).
39 ~~43~~.	Victorville/Lugo - Rio Hondo	Azusa	To Rio Hondo	PVNGS Firm Transmission Service Agreement	373~~247.6~~	Earliest of: termination agreement, Azusa's 1-year notice given after 1/1/02, termination of PVNGS entitlement, or termination of PVNGS participation.	4 MW
40 ~~4~~.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	To Banning	PVNGS Firm Transmission Service Agreement	379~~248.7~~	Earliest of: agreement to terminate, or Banning's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
41 ~~5~~.	Victorville/Lugo - Vista	Colton	To Vista	PVNGS Firm Transmission Service Agreement	362~~249.4~~	Earliest of: agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
42 ~~6~~.	Victorville/Lugo - Vista	Riverside	To Vista	PVNGS Firm Transmission Service Agreement	392~~250.10.10~~	12/31/2002 - Per 1997 Edison-Riverside Restructuring Agreement, unless City elects to replace the rate methodology contained therein with the ISO's rate methodology for transmission service.~~Earlier of: agreement to terminate, or termination of 1990 IOA, Riverside's entitlement in PVNGS, ANPP Agreement, SRP-WAPA Mead-Liberty FTS Agreement, or SRP-SCPPA ITS~~	~~11.691~~ 12 MW (per 1997 Edison – Riverside Restructuring Agreement).

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

						~~Agreement.~~	
~~47.~~	~~Victorville/Lugo - Lewis~~	~~San Juan for Anaheim~~	~~Bi-dir.~~	~~1995 San Juan Unit 4 FTS~~	~~246.33~~	~~Earliest of: 12/31/02, or agreement to terminate, or 1-year notice, except service will not terminate prior to 12/31/01.~~	~~1998-2000, 450MW June-Sept, 300 MW other months; 2001-2002, 450MW June-Sept, 350 MW other months.~~

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT - DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
43 ~~8.~~	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360~~154.2 4~~	Terminates with permanent removal of Mead-Adelanto from service	11 MW
44 ~~9.~~	Victorville/Lugo –Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360~~154.2 4~~	Up to term of agreement	64 MW
~~50.~~	~~Victorville/Lugo - Vista~~	~~Deseret for Riverside~~	~~To Vista~~	~~Edison-Riverside 1992 Deseret Firm Transmission Service Agreement~~	~~250.27.3~~	~~Earlier of: agreement to terminate, or termination of 1990 IOA, Power Sale Agreement, LADWP NTS Agreement, SCPPA STS Agreement, or LADWP IPP Additional Capacity Agreement~~	~~49.92 MW~~
45 ~~4.~~	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	Bi-dir.	Sylmar Firm Transmission Service Agreement	380~~248.2 4~~	Earliest of agreement to terminate, or Banning's 1-year notice given after 1/1/02, or termination of Bannings interest in San Juan #3.	5 MW
46 ~~52.~~	Victorville/Lugo - Rio Hondo	Azusa	to Rio Hondo	Pasadena FTS	374~~247.8~~	*Earliest of agreement to terminate,* or Azusa's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	14 MW
47 ~~53.~~	Victorville/Lugo - Vista	Colton	to Vista	Pasadena FTS	363~~249.8~~	Earliest of agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	18 MW

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	~~POINT OF RECEIPT - DELIVERY~~	~~PARTIES~~	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
48 ~~54.~~	Sylmar - Rio Hondo	Azusa	To Rio Hondo	1995 San Juan Unit 3 FTS Agreement	37624 ~~7.29~~	Earlier of: termination of Azusa's interest in San Juan Unit #3 or Azusa's 1-year notice given after 1/1/02	Sum of 10 MW continuous plus 15 MW (May through October 1999 through 2003) (Per 1997 Edison – Azusa Restructuring Agreement)
49 ~~55.~~	Sylmar - Goodrich	Pasadena	Sylmar-Goodrich	Pasadena-Edison 230-kV Interconnection and Transmission Agreement	55	8/4/10	200 MW; Edison also responsible for delivery of up to 15 MW of Azusa Hydro Energy to Pasadena at Goodrich
~~56.~~	~~Sylmar - Riverside~~	~~Riverside~~	~~Bi-dir.~~	~~Sylmar Firm Transmission Service Agreement~~	~~250.3~~	~~Earliest of: termination of 1990 IOA, or 20 years from date FTS first provided, or 12/31/09~~	~~23 MW~~
~~57.~~	~~Sylmar - Riverside~~	~~Riverside~~	~~Bi-dir.~~	~~Washington Water Power Firm Transmission Service Agreement~~	~~250.35~~	~~Earliest of: termination of 1990 IOA, or 20 years from date FTS first provided, or 12/31/09~~	~~25 MW~~
50 ~~8.~~	Sylmar - Vista	Colton	Bi-dir.	Sylmar Firm Transmission Service Agreement	36424 ~~9.24~~	Earliest of: agreement to terminate, or Colton's 1-year notice given after 1/1/02, or termination of Idaho service contract.	3 MW
51 ~~9.~~	Sylmar - Midway	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: termination of PG&E Transmission Agreement, or	93 MW until 1/1/00,

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

						12/29/42 (50 yrs).	93MW after 12/31/07
52 ~~60~~.	Sylmar - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Earlier of: term of PG&E Transmission Agreement or 12/29/42 (50 yrs).	93 MW until 12/31/02, 60 MW after 12/31/02

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

[illegible]		[illegible]	DIR	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
53 ~~61~~.	Sylmar - SONGS	SDG&E	To SDG&E	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	100 MW
54 ~~62~~.	Sylmar - SONGS	SDG&E	To Sylmar	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	105 MW
55 ~~63~~.	Sylmar - Vincent	CDWR	Bi-dir.	Amended and Restated Power Contract	112 First Revised	12/31/04	120 MW
56 ~~64~~.	Sylmar - Mead	PG&E	To Mead.	Amended and Restated Edison-PG&E Transmission Agreement	256 First Revised	7/31/07	Up to 200 MW of FTS.

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT/DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~65.~~	~~City Gate~~	~~Anaheim~~		~~1990 Power Sale Agreement~~	~~251~~	~~12/31/1998~~	~~25 MW~~
~~66.~~	~~City Gate~~	~~Azusa~~		~~1990 Power Sale Agreement~~	~~252~~	~~12/31/1998~~	~~12 MW~~
~~67.~~	~~City Gate~~	~~Banning~~		~~1990 Power Sale Agreement~~	~~253~~	~~12/31/1998~~	~~4 MW~~
~~68.~~	~~City Gate~~	~~Colton~~		~~1990 Power Sale Agreement~~	~~254~~	~~12/31/1998~~	~~30 MW~~
~~69.~~	~~City Gate~~	~~Riverside~~		~~1990 Power Sale Agreement~~	~~255~~	~~12/31/1998~~	~~30 MW~~
57 ~~70.~~	Point of Delivery: COB or NOB	BPA	S-N	Long Term Power Sales & Exchange Agreement	222	Per five year notice from BPA dated 10/29/1999, contract will terminate early on 11/1/2004~~5/31/2009 or upon 5 years' notice~~	Up to 850 MW under the exchange modes.
~~71.~~	~~Point of Delivery: COB or NOB~~	~~BPA~~	~~S-N~~	~~Environmental Energy Storage Agreement~~	~~341~~	~~3/31/2005 or upon 3 years' notice~~	~~Up to 200 MW under return mode.~~
58 ~~72.~~	Point of Delivery: Midway or 500 kV bus at Vincent	CDWR	S-N	Amended and Restated Capacity Exchange Agreement	148 First Revised	12/31/2004	Depending on time and day: Minimum=225 MW Maximum=1550 MW for both the Power Contract and Capacity Exchange Agreement
59 ~~73.~~	Point of Delivery: Midway or 500 kV bus at Vincent	CDWR	S-N	Amended and Restated Power Contract	112 First Revised	12/31/2004	Included under Capacity Exchange Agreement Contract Amount Column

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT/DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~74.~~	~~Point of Delivery: COB, NOB, Four Corners~~	~~PacifiCorp~~	~~S-N W-E~~	~~Winter Power Sale Agreement~~	~~278~~	~~03/15/03 or 03/15/08 if extended upon agreement of the parties prior to 3/15/2000~~	~~Up to 422 MW~~
~~75.~~	~~Point of Delivery: Midway~~	~~SMUD~~	~~S-N~~	~~1994-1999 Power Sale Agreement~~	~~335~~	~~12/31/1999~~	~~Up to 200 MW~~
~~76.~~	~~Point of Delivery: Midway~~	~~SMUD~~	~~S-N~~	~~(1990-99) Power Sale Agreement~~	~~238~~	~~12/31/1999~~	~~200 MW~~
60 ~~77.~~	Point of Delivery: Palo Verde, Four Corners, Moenkopi	Tucson	W-E	Amended and Restated Tucson Power Exchange Agreement	271 First Revised	5/14/2005	110 MW
~~78.~~	~~Point of Delivery: Mead~~	~~Nevada~~	~~W-E~~	~~Nevada Power Purchase Agreement~~	~~286~~	~~9/30/2000~~	~~100 MW~~
61 ~~79.~~	Hoover - Mead	WAPA	Bi-dir.	Lease of Two 230-kV Transmission Lines Between Hoover Power Plant and Mead Substation	304	9/30/2017 or upon 3-years' notice by WAPA; WAPA entitled to renew through life of Hoover.	Entire capacity leased to WAPA.

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	~~POINT OF RECEIPT/DELIVERY~~	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT	
~~80.~~	~~N/A~~	~~Riverside~~	~~N/A~~	~~1972 Settlement Agreement~~	~~N/A~~	~~N/A~~	~~N/A~~	
~~81.~~	~~Various~~	~~Riverside~~		~~1990 Integrated Operations Agreement~~	~~246~~	~~2/1/2000~~		
~~82.~~	~~From Edison - Vista~~	~~Riverside~~	~~to Vista~~	~~Partial Requirements: Rate Schedule R-6.3~~	~~17.25.12~~	~~N/A~~	~~varies~~	
~~83.~~	~~N/A~~	~~So. Cal. Water Co.~~	~~N/A~~	~~1972 Settlement Agreement~~	~~N/A~~	~~N/A~~	~~N/A~~	
~~84.~~	~~From Edison - Vista~~	~~So. Cal. Water Co.~~	~~to Vista~~	~~Partial Requirements: Rate Schedules R-8.0;~~ ~~Transmission Service Agreement;~~ ~~Added Facilities Agreement~~	~~349~~ ~~349~~ ~~349~~	~~12/31/2001~~ ~~Upon termination of service to HarnishSub~~ ~~Upon 5-years' notice given after year 2036, or on 1-year's notice from So. Cal. Water given after 1/1/2001~~	~~5 MW, until removal under terms of Added Facilities Agreement, then 0 MW~~	
~~85.~~	~~From Edison - Victor~~	~~So. Cal. Water Co.~~	~~to Victor~~	~~Partial Requirements: Rate Schedule R-8.0;~~ ~~Transmission Service Agreement;~~ ~~Added Facilities Agreement~~	~~349~~ ~~349~~ ~~349~~	~~12/31/2001~~ ~~Upon termination of service to HarnishSub.~~ ~~Upon 5-years' notice given after year 2036, or on 1-year's notice from So. Cal. Water given after 1/1/2001~~	~~30 MW, until addition of Added Facilities, then 50 MW~~	
~~86.~~	~~Edison Interconnections-Interconnection with So. Cal. Water~~	~~So. Cal. Water Co.~~	~~To So. Cal. Water~~	~~Control Area Import Agreement~~	~~349~~	~~12/31/2001~~	~~50MW~~	

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
~~87.~~	~~Vincent - Vista~~	~~Riverside~~	~~To Vista~~	~~CDWR Power Sale II~~ ~~III~~ ~~IV~~ ~~V~~	~~250.21~~ ~~250.46~~ ~~250.44~~ ~~250.50~~	~~3/1/1999~~ ~~10/31/2010~~ ~~10/31/2010~~ ~~9/30/1998~~	~~20 MW~~ ~~23 MW~~ ~~30 MW~~ ~~50 MW~~
62 ~~88.~~	Calectric - Vincent	CDWR	To Vincent	Amended and Restated CDWR Devil Canyon Power Plant Additional Facilities and Firm Transmission Service Agreement	421~~112.3~~	Life of Plant	~~55~~ 120 MW
63 ~~89.~~	Mojave Siphon - Vincent	CDWR	To Vincent	CDWR Mojave Siphon Additional Facilities and Firm Transmission Service Agreement	342	Life of Plant	28 MW
64 ~~90.~~	Vincent - Oso	CDWR	to Oso	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	72 MW
65 ~~91.~~	Vincent - Pastoria	CDWR	to Pastoria	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	787 MW
66 ~~92.~~	Wame - Vincent	CDWR	To Vincent	Amended and Restated CDWR Power Contract	112 First Revised	12/31/2004	82 MW
67 ~~93.~~	Vincent - Pearblossom	CDWR	To Pearblossom	Amended and Restated CDWR Power Contract	112 First Revised	12/~~01~~31/2004	152 MW
68 ~~94.~~	Blythe - Cibola, & Ehrenberg (Buckskin service does not go through ISO system)	APS	To APS Load	Amended and Restated Firm Transmission Service (Blythe Accounts)	348 First Revised	Upon 3-year notice by APS, or 10 year notice by Edison	Presently 4.2 MW, 7 MW max.
69.	Malin – Round Mountain - Tracy	USBR (WAPA), California Companies	Bi-directional	USBR Contract with California Companies for Extra High Voltage Transmission And Exchange Service	37	1/1/2005	400 MW
70.	COB – Midway	State of CA. (CDWR), California Companies	Bi-directional	Contract between State of California and California Companies for the Sale, Interchange, and Extra High Voltage Transmission of	38	1/1/2005	300 MW

~~TCA APPENDIX B: EDISON'S CONTRACT ENCUMBRANCES~~

			Electrical Capacity and Energy					

SDG&E APPENDIX B

SDG&E'S ENCUMBRANCES

I. Local Furnishing Transmission System Encumbrances

The ISO shall exercise Operational Control over SDG&E's Local Furnishing Transmission System consistent with the following Encumbrances in accordance with the Local Furnishing Debt Operating Procedures that SDG&E has provided the ISO:

A. Section 9600(a)(6) of the California Public Utilities Code provides that Participating TOs shall not be compelled to violate restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding use of transmission facilities existing as of December 20, 1995.

SDG&E's transmission facilities and other electric properties are financed in part with the proceeds of Local Furnishing Bonds. Prior to December 20, 1995, pursuant to provisions of the loan agreement, engineering certificates, and tax certificates and agreements associated with outstanding Local Furnishing Bonds issued for its benefit, SDG&E has convenanted not to take or permit any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit. Accordingly, notwithstanding anything to the contrary contained in the Agreement, including SDG&E's agreement to be bound by the terms of the Restated and Amended ISO Tariff and the Restated and Amended TO Tariff, SDG&E may not take (nor may SDG&E allow the ISO to take) any action that would jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, including (without limitation) the actions specified below.

B. Absent an approving written opinion of nationally recognized bond counsel selected by SDG&E, SDG&E will not operate its facilities (or allow its facilities to be operated) so as to cause or permit a cumulative annual net outbound flow of electric energy from the points of interconnection between (i) SDG&E's wholly-owned transmission lines which are directly connected to SDG&E's electric distribution facilities in San Diego and Orange Counties, and (ii) other electric properties. As of January 1, 1998, these interconnection points include:

1. the point at the International Border where SDG&E's ownership interest in the 230 kV Miguel/Tijuana transmission

line interconnects with Comision Federal de Electridad's ownership interest in the Miguel/Tijuana transmission line;

2. the set of points at the San Onofre Nuclear Generating Station ("SONGS") where SDG&E's wholly-owned transmission facilities interconnect with a switchyard but which is owned (in whole or in part) by Southern California Edison Company ("SCE");

3. the point where SDG&E's wholly-owned segment of the 500 kV Miguel/Imperial Valley transmission line interconnects with the Imperial Valley Substation;

4. the point at the San Diego/Imperial Valley border where SDG&E's ownership interest in a 2.5 mile-long radial distribution line interconnects with Imperial Irrigation District's ownership interest in that same distribution line;

5. the point at the Riverside/Orange County border and the Riverside/San Diego County border where SDG&E's ownership interest in several isolated distribution lines interconnect with SCE's ownership interest in those same distribution lines;

6. the point where SDG&E's wholly-owned Narrows Substation intereconnects with transmission facilities which are owned by Imperial Irrigation District.

C. For purposes of paragraph B, net flows shall be calculated by treating as an outbound flow at the SONGS switchyard bus all electric energy generated at SONGS on behalf of SDG&E (i.e., consequent to SDG&E's interest in SONGS) that is not transmitted into SDG&E's electric service area in San Diego and Orange Counties. Electric energy generated at SONGS on behalf of SDG&E that is transmitted into SDG&E's service area, whether for delivery to retail customers of SDG&E or for other uses, shall not be treated as an inbound flow at the SONGS switchyard bus interconnection for purposes of this calculation.

D. SDG&E will not operate its facilities (or allow its facilities to be operated) so as to curtail delivery of electric energy to its native load customers involuntarily in order to provide electric energy to customers outside of its electric service territory in San Diego and Orange Counties, unless such curtailment is necessitated by the failure of facilities either partially or wholly owned by SDG&E.

E. Upon SDG&E's receipt of a written request by the ISO to take (or to refrain from taking) any action that SDG&E believes might jeopardize the tax-exempt status of interest on Local Furnishing Bonds issued for its benefit, SDG&E in good faith shall promptly seek to obtain an opinion (of the type generally regarded in the municipal bond market as unqualified) from a nationally recognized bond counsel selected by SDG&E that the requested action (or inaction) will not adversely affect such tax-exempt status. Until the opinion of bond counsel described above is obtained, SDG&E shall not be required to take (or to refrain from taking) the specified action, and the ISO shall exercise its Operation Control consistent with such limitation.

F. If the ISO proposes to set rates for transmission over SDG&E's transmission facilities based in whole or in part upon the costs to Participating Transmission Owners other than SDG&E (see, e.g., California Public Utilities Code § 9600(a)(2)), the ISO will return Operating Control over SDG&E's transmission facilities to SDG&E unless SDG&E, in good faith, has obtained an opinion (of the type generally regarded in the municipal bond market as unqualified) from nationally recognized bond counsel selected by SDG&E that the proposed ratemaking will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E.

G. If SDG&E has been unable to obtain the unqualified opinion of bond counsel described in sections E and F above, upon written request by a entity eligible to file an application under Section 211 of the Federal Power Act ("FPA")(or the ISO acting as its agent)(collectively, the "Eligible Entity"), SDG&E in good faith shall promptly seek to obtain a ruling from the Internal Revenue Service that the requested action (or inaction) or transmission rates will not adversely affect the tax-exempt status of interest on Local Furnishing Bonds issued for the benefit of SDG&E. If such a ruling cannot be obtained, SDG&E will not object to an Eligible Entity seeking an order under Section 211 of the FPA with respect to the requested action (or inaction) or transmission rates.

II. Mortgage Lien

The ISO shall acknowledge the mortgage lien set forth below:

A. The lien of the Mortgage and Deed of Trust dated July 1, 1940 between San Diego Gas & Electric Company and The Bank of California, as trustee, as amended and supplemented and in effect on the date hereof (the "SDG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the property subject to the SDG&E Mortgage which would be prior to the lien of the SDG&E Mortgage; however, no consent of the trustee under the SDG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

APPENDIX B.2

SDG&E's List of Contract Encumbrances[1]/[2]

CONTRACT NUMBER	CONTRACT NAME	OTHER PARTIES	FERC NO.	CONTRACT TERMINATION	FACILITY/PATH, AMOUNT OF SERVICE
81-034	Mutual Assistance Transmission Agreement	IID, APS, Edison	62	4/12/2034 or sooner by mutual agreement of the parties.	In the event of a contingency in the Palo Verde-Devers, Palo Verde-North Gila-Imperial Valley transmission lines, participants to share the available capacity based on predetermined operating procedures set out in a separate operating bulletin.
79-016	SONGS Participation Agreement	Edison, Anaheim, Riverside	321	None	SDG&E's share of SONGS switchyard with termination of its 230 kV transmission lines: - San Luis Rey Tap - Mission - Talega (2 lines) - Encina
79-017	IID-SDG&E Interconnection and Exchange Agreement	IID	065	June 24, 2051 (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, IID and SDG&E to provide each other emergency capacity and energy without charge.
78-007	CFE-SDG&E Interconnection and Exchange Agreement	CFE		12 month notice (schedule pertaining to emergency capacity/energy services is expected to be terminated upon execution by IID of the ISO's Control Area Agreement).	Should a contingency occur due to loss or interruption of generating or transmission capabilities on either party's electric system, CFE and SDG&E to provide each other emergency capacity and energy.

---

[1] An additional encumbrance pertaining to Local Furnishing Bonds that does not fit into the format for existing contract encumbrances is set forth at pages SDG&E App. B-1 through B-3 hereof.

[2] An additional encumbrance pertaining to SDG&E's lien of Mortgage and Deed of Trust that does not fit into the format for existing contract encumbrances is set forth at page SDG&E App. B-4 hereof.

81-005	Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement	APS, IID, PNM, SRP, El Paso, SCE, SCPPA	063	July 31, 2031	In the event that the capacity of the ANPP Switchyard is insufficient to accommodate all requests, the rights of the ANPP Switchyard Participants shall take precedence in all allocations.
81-050	IID-SDG&E Transmission System Participation Agreement	IID		June 24, 2051	SDG&E and IID schedule power and energy over the California Transmission System for their respective accounts at the Yuma (North Gila) 500kV Switchyard for delivery to the 500 kV breaker yard of the Imperial Valley in the following percentages of operating capacity: SDG&E – 85.64%; and IID – 14.36%.
78-003	APS-SDG&E Transmission System Participation Agreement	APS		July 31, 2031	SDG&E, APS, and IID schedule power and energy over the Arizona Transmission System for their respective accounts at the Palo Verde Switchyard for delivery at the Yuma (North Gila) 500 kV Switchyard in the following percentages of operating capacity: APS – 11%; SDG&E - 69%; IID - 20%.
QFD000.016	Power Sale Agreement between SDG&E-City of Escondido for the Rincon Indian Reservation	City of Escondido	76	Agreement to be terminated effective upon FERC acceptance of Notice of Termination.	Obligates SDG&E to sell and deliver electricity at stated prices to the City of Escondido for resale to the United States Indian Services at the Rincon Indian Reservation.

1/ TANC's 300 MW is firm bi-directional service using the Points of Receipt and Delivery set forth in section 2.4 of the SOTP and in accordance with the Curtailment Priorities set forth in section 3.2 of the SOTP. PG&E supports these transfer capabilities by implementing mitigation measures when necessary, to the extent such measures are available, up to a total of 200 MW south-to-north and 700 MW north-to-south. These mitigation measures consist of switching PG&E's scheduled transmission service from the AC Lines to the DC Line.

APPENDIX B: CITY OF VERNON'S

ENCUMBRANCES

[illegible]	PARTIES	DIRECTION	CONTRACT TITLE	FERC NO.	CONTRACT TERMINATION	CONTRACT AMOUNT
1. ~~North to South on~~ COTP [1] ~~South to North on COTP~~	Vernon, PG&E		Transmission Service Exchange Agreement Between Pacific Gas & Electric Company and the City of Vernon	148	See Notes (1) – (3)	121 MW N-S 92 MW S-N
2.	PG&E, SCE, ~~and~~ SDG&E, and COTP Participants		Coordinated Operation Agreement	~~[2]~~146	Earlier of: 1/1/2043, agreement governing the interconnection of the COTP with PG&E is no longer in force, or any of the binding agreements terminate.	

Contract Termination: ~~(Transmission Service Exchange Agreement Between Pacific Gas & Electric Company and the City of Vernon):~~

(1) This Agreement may be terminated on July 31, 2007:

- A. By PG&E with one year notice to Vernon if PG&E has not retained for the remaining term of this Agreement at least a 659 MW transmission entitlement in *DC Line* at *NOB*.
- B. By Vernon if PG&E's entitlement in the DC Line after July 2007 results in an arrangement for the operation of DC Line as to reduce transmission capability.
- C. *If the DC Line or COTP facilities are retired.*

(2) In the event City elects to participate in an alternative project that provides City with transmission capability between the Southern Terminus of COTP and Edison's system, City may terminate this Agreement by written notice to PG&E at least five (5) years in advance of such termination.

(3) Otherwise, the Agreement remains in effect for fifty years from the effective date.

[1] PG&E is an existing *PTO* and *a joint-owner* of COTP. We believe documents relating to the COTP are submitted to the CAISO by PG&E.

~~[2] Pursuant to Docket No. ER92-626-000~~

Vernon has only minority ownership interests in the high voltage transmission facilities presently placed under the ISO's Operational Control by Vernon, which consist of Vernon's minority interests in COTP, MPP, MAP, and the Marketplace Substation/Expansion of and/or interconnection to these facilities require approval of the owners and/or the management committees of those facilities. Therefore, as the Commission determined in approving Vernon's TO Tariff in Docket No. EL00-105, 96 FERC ¶ 61,312 (September 14, 2001), Vernon does not have the legal authority to compel expansion of and/or interconnection to those facilities. Such encumbrances pertaining to Vernon's minority interests in the facilities turned over to ISO operational control that do not fit into the format of the table above are listed below:

Mead-Phoenix Project

1. Mead-Phoenix Project Joint Ownership Agreement and Definitions
2. Mead-Phoenix Project Fiscal Agency Agreement
3. Mead-Phoenix Project Construction Management Agreement
4. Mead-Phoenix Project Land Rights Agreement
5. Mead-Phoenix Project Operation Agreement
6. Mead-Phoenix Project, Mead-Westwing *Transmission Line, Westwing Substation Interconnection* Agreement (DWP No. 10408)
7. Mead-Phoenix Project, Mead Interconnection Agreement

Mead-Adelanto Project

8. Marketplace Substation Participation Agreement (DWP No. 10330)
9. Mead-Phoenix/Mead-Adelanto Projects, Marketplace-McCullough 500 kV Interconnection Agreement (DWP No. 10409)
10. Mead-Adelanto Project Joint Ownership Agreement and Definitions
11. Mead-Adelanto Project Fiscal Agency Agreement
12. Mead-Adelanto Project Construction Management Agreement (DWP No. 10335)
13. Mead-Adelanto Project Operation Agreement (DWP No. 10336)
14. Mead-Adelanto Project, Marketplace-Adelanto Transmission Line, *Adelanto Switching Station Interconnection Agreement* (DWP No. 10338)
15. Marketplace Static Var Compensator, Adelanto Switching Station Interconnection Agreement (DWP No. 10332)

California-Oregon Transmission Project

1. Interim Participation Agreement
2. Project Operation and Maintenance Agreement
3. COTP-Western Interconnection Agreement
4. Pacific Northwest Interim Interconnection Agreement
5. Memorandum of Understanding

APPENDIX B: CITY OF ANAHEIM ENCUMBRANCES

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1	Mona Substation-Gonder Substation	Anaheim-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		7-Jun-94	31-Dec-09	20 MW

APPENDIX B: CITY OF AZUSA
ENCUMBRANCES

[redacted]						
1. ANPP (Devers) - Sylmar	Azusa, Los Angeles		Los Angeles - Azusa ANPP/Sylmar FTS	DWP No. 10021		10 MW

Los Angeles – Azusa ANNP/Sylmar FTS:
Pursuant to Section 6.2 of the Los Angeles – Azusa ANNP/Sylmar FTS, the Los Angeles Department of Water and Power is entitled to schedule energy on a nonfirm basis over the 10 MW of bidirectional transmission service between Palo Verde and Sylmar to the extent Azusa does not use the transmission service.

Summary- details are in each agreement.

APPENDIX B: CITY OF RIVERSIDE ENCUMBRANCES

Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1. Mona Substation-Gonder Substation	Riverside-Deseret G&T	Bi-directional	Mona-Gonder Transmission Service Agreement		17-Jun-94	31-Dec-09	20 MW

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO MAINTENANCE STANDARDS

1. DEFINITIONS[1]

Availability - A measure of time a Transmission Facility under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures - The frequency and accumulated duration of Forced Outages$^{(IMS)}$ for each of the Transmission Line Circuits within a Voltage Class for a given calendar year.

Availability Measure Targets- The Availability performance goals established by the ISO.

Forced Outage$^{(IMS)}$ - A Forced Outage$^{(IMS)}$ occurs when a Transmission Facility is in an Outage$^{(IMS)}$ condition regardless of duration and: (1) there is no Scheduled Outage request in effect with respect to that period; or (2) the Transmission Facility is in an Outage$^{(IMS)}$ condition for a period that exceeds the period specified in the Scheduled Outage request, in which case a Forced Outage$^{(IMS)}$ is deemed to exist for the balance of the period, unless the PTO requests and is granted an extension to the approved Scheduled Outage request.

ISO Maintenance Guidelines - Criteria presented herein which are to be followed by each PTO in preparing its PTO Maintenance Practices.

[1] A term followed by the supercript "(IMS)" denotes a term which has a special, unique definition in this Appendix.

ISO Maintenance Standards - Those maintenance standards which result from the combination of each PTO's Maintenance Practices and their respective Availability Measures.

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities.

Maintenance Coordination Committee - A committee responsible for recommending to the ISO modifications to and implementation of the ISO Maintenance Standards. The committee shall be organized and operate in accordance with Section 7.0 of this document.

Outage$^{(IMS)}$ - Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO - A Participating Transmission Owner as defined in Appendix D of the Transmission Control Agreement.

PTO Maintenance Practices - A description of methods used by a PTO for the Maintenance of each substantial type of Transmission Facility or component in its system which is under the Operational Control of the ISO. The PTO Maintenance Practices are to be prepared in accordance with the ISO Maintenance Guidelines.

Scheduled Outage - The removal from service of a Transmission Facility under ISO Operational Control to perform work on specific components in accordance with the requirements of the Transmission Control Agreement.

Section 348 Criteria - The criteria for maintenance standards established by Section 348 of the California Public Utilities Code, as in effect from time to time, to "provide for high quality, safe and reliable service", taking into consideration "cost, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience".

Stations - Facilities under the Operational Control of the ISO for purposes such as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and system protection equipment.

Transmission Line Circuit - The continuous set of transmission conductors located primarily outside of a Station, and apparatus terminating at interrupting devices which would be isolated from the transmission system following a fault on such equipment.

Voltage Class - The voltage to which operating, performance, and maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

2. INTRODUCTION

These standards were prepared by the ISO through a lengthy consensus building effort involving a diverse group of stakeholders (i.e., the ISO Maintenance Standards task force).

2.1. Objective

The Maintenance of Transmission Facilities has several objectives:

- Ensuring that the safety and Availability performance levels inherent to the Transmission Facilities are achieved,
- Restoring the safety and Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Gathering information that can be of use as the basis for identifying improvements to those Transmission Facilities whose Availability performance is inadequate,
- Gathering information that can be used as the basis for optimizing and forecasting Maintenance for Transmission Facilities,
- Extending the useful life of the Transmission Facilities while maintaining their inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum total cost for Maintenance and Outages.

The ISO Maintenance Standards address the following topics:

- Transmission Facilities Covered by the ISO Maintenance Standards;
- Availability Measures ;
- Availability Measure Targets;
- ISO Maintenance Guidelines for PTO Maintenance practices;
- Qualifications of Maintenance Personnel;
- Maintenance Record Keeping and Reporting;
- Establishment of a Maintenance Coordination Committee;
- Process for the Revision of the ISO Maintenance Standards;
- Incentives and Penalties for PTO Availability Performance;
- Compliance with Laws and Regulations; and
- Dispute Resolution.

For certain aspects of Maintenance, these Standards delineate specific requirements and responsibilities (e.g., requirements for PTO inspection and Maintenance records), for others they provide guidelines (e.g., contents of PTO Maintenance Practices documents), and for others they describe processes (e.g., review process for PTO Maintenance Practices documents) to be enacted to achieve the desired results.

Flexibility in establishing ISO Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, the ISO Maintenance Standards are founded on two basic precepts: 1) the effectiveness of each PTO's Maintenance will be gauged through an Availability performance monitoring system, and 2) the adequacy of each PTO's Maintenance Practices will be assessed through ISO review. Each PTO's Maintenance Practices will serve as the ISO's Maintenance Standards for the Transmission Facilities covered therein. The PTO Maintenance Practices ensure a reasonable level of Maintenance during the short term while Availability is used to monitor long term performance.

It is the belief of the ISO Maintenance Standards task force that it is impractical for the ISO to develop and/or impose on the PTO's a single uniform set of detailed descriptions of practices delineating condition or time-based schedules for various Maintenance activities that account for the myriad equipment, operating conditions, and environmental conditions within the ISO grid. For this reason, the ISO Maintenance Standards provide ISO Maintenance Guidelines to be followed by each PTO in preparing PTO Maintenance Practices for its Transmission Facilities.

2.2. Availability

ISO grid reliability is a function of the Availability of Transmission Facilities owned and operated by its PTO's. The key to the effectiveness of the ISO Maintenance Standards is the establishment of a consistent measure of Transmission Facility Availability (Availability Measures) and the initial setting of the Availability Measure Targets as well as periodic revisions of those targets. By measuring Availability the ISO is able to monitor the effectiveness of Maintenance. While the ISO is concerned with grid reliability, reliability is a function of a complex set of variables including the accessibility of alternative load paths, speed and sophistication of protective equipment, and the Availability of Transmission Line Circuits, and therefore is indirectly related to Maintenance. Thus, Availability will be the principal determinant of each PTO's performance under the ISO Maintenance Standards.

When using Availability as a gauge of Maintenance adequacy, several things must be kept in mind to avoid misinterpreting performance. The most important consideration is that across the ISO grid, the vast majority of all Forced Outages[(IMS)] are due to random/chance events that cannot be controlled by Maintenance. It is important to recognize that only a small percentage of all Forced Outages[(IMS)] can be controlled through Maintenance (i.e. activities that do not change the basic configuration of Transmission Facilities). This principle assumes the PTO is performing a reasonable level of Maintenance consistent with Good Utility Practice. If an unreasonably low level of Maintenance is performed for a sufficient period of time, Availability will decline. However, if a level of Maintenance is being performed, consistent with Good Utility Practice, increasing Maintenance activities by a significant order will not result in a corresponding increase in Availability. Thus, while Maintenance is important to ensuring Availability, drastic increases in Maintenance will not lead to substantial improvements in Transmission Facility Availability and associated grid reliability.

A variety of techniques can be used to monitor performance, however techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of performance. To account for random/chance variations while enabling monitoring for shifts and trends in performance, control charts have been widely accepted as an effective means for monitoring performance. Control charts are statistically-based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge the adequacy of performance. Availability is affected by several factors only one of which is Maintenance. In fact, for most Transmission Line Circuits only a small fraction of Forced Outages$^{(IMS)}$ can be attributed to phenomenon that could be controlled or avoided through Maintenance. Many more Forced Outages$^{(IMS)}$ are attributable to random/chance events than Maintenance-related items. Therefore, while monitoring Availability as a gauge of Maintenance adequacy is useful for evaluating long term trends, care must be taken to avoid reading too much into the correlation of Availability to Maintenance since so many additional variables also impact Availability.

The fundamental performance measures selected as the basis for developing an Availability performance monitoring system are the annual accumulated duration and frequency of certain types of Outages for each Transmission Line Circuit under the ISO's Operational Control. To enhance the Availability performance monitoring system's use as a gauge of Maintenance adequacy, it was necessary to exclude certain Outage$^{(IMS)}$ types from the determination of the performance measures. Those excluded Outages are:

- Scheduled Outages;
- Outages caused by events originating outside the PTO's system; and
- Outages demonstrated to have been caused by earthquakes.

Additionally, the Forced Outage$^{(IMS)}$ duration has been capped at 72 hours so that excessively long Forced Outages(IMS) do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage(IMS) duration. This is not to say that an excessively long Forced Outage(IMS) is not a concern. Rather, such Forced Outages(IMS) should be investigated to assess the reasons for their extended duration.

The performance monitoring system requires use of separate control charts for each Voltage Class and PTO. Existing Forced Outage(IMS) data contains significant differences in the Availability performance between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. However, regardless of the cause of the differences, review of the Forced Outage(IMS) data makes it eminently apparent that the performance differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts will be constructed to provide a complete representation of historical Availability performance, and to provide a benchmark against which future performance can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage(IMS) frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage(IMS) duration for those Transmission Line Circuits which experience Forced Outages(IMS); and
- The annual proportion of Transmission Line Circuits that experienced no Forced Outages(IMS).

These three control charts will assist the ISO and PTO's in assessing the performance of Voltage Classes over time. To accommodate this process on a cumulative basis data are made available to the ISO by each PTO at the beginning of a new year to assess the performance of the past years.

2.3. ISO Maintenance Guidelines

Two specific requirements regarding Maintenance documentation have been incorporated into the ISO Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance practices (PTO Maintenance Practices) to the ISO. Second, these standards require that each PTO maintain Maintenance records and make those records available to the ISO in order to demonstrate compliance with each element of its PTO Maintenance Practices.

To outline the fundamental requirements for, and to promote consistency in the PTO Maintenance Practices, these standards provide guidelines for the preparation and maintenance of the PTO Maintenance Practices. These ISO Maintenance Guidelines provide for flexibility in approach to Maintenance, but also require the description of certain specific Maintenance practices. The guidelines require that the PTO's provide descriptions of the various Maintenance activities, schedules and condition triggers for performing the Maintenance, and samples of any checklists, forms, or reports used for Maintenance activities.

2.4. Data Standards

To facilitate processing of Outage$^{(IMS)}$ data for the Availability performance monitoring system, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The ISO and PTO's have committed to developing standardized formats for transmitting Outage$^{(IMS)}$ data to the ISO for the Availability performance monitoring system. These standard formats are to be finalized within the first 60 days of 1998. Additionally, the ISO and PTO's have agreed to develop and implement a standard Maintenance reporting system by the end of the third year of operation of the ISO. This system will provide for consistent gathering of information that can be used as the basis for optimizing and forecasting maintenance of Transmission Facilities. The development of such a Maintenance reporting system is consistent with fostering the spirit of cooperation among the ISO and the PTO's as it may eventually aid in the resolution of performance problems, and provide the basis for research on an ISO grid-wide basis to identify opportunities to enhance Transmission Facility Maintenance.

2.5. Applicability of Incentives and Penalties

Cooperation and collaboration among the PTOs responsible for ensuring the Availability of the Transmission Facilities comprising the ISO grid are needed to ensure the most reliable grid possible. Therefore, the ISO Maintenance Standards task force believes that a formal program of incentives and penalties tied purely to PTO Maintenance may hinder needed cooperation among PTOs. As a result, the ISO Maintenance Standards task force recommends that no such program be instituted initially by the ISO.

Further, the task force recognizes the need for the ISO to enforce reasonable Maintenance to ensure Availability in the case that: 1) a PTO exhibits degradation in Availability performance due to Maintenance, 2) a PTO does not comply with its PTO Maintenance Practices, or 3) a PTO is grossly or willfully negligent with regards to Maintenance. Therefore, it is the position of the ISO Maintenance Standards task force that it is reasonable for the ISO to establish penalties for such conditions. In the absence of a formal program of incentives and penalties, the task force acknowledges the ISO's right to pursue sanctions for cause on a case by case basis.

Availability is a useful and tractable means for monitoring performance, however, the electric utility industry as a whole has little experience in using Availability to gauge the adequacy of Maintenance. Further, because the industry in general has not carefully managed historical Outage$^{(IMS)}$ data to the degree that is necessary to make them useful for performance monitoring, there are varying limitations with regards to the accessibility and reliability of Outage$^{(IMS)}$ data among PTOs. Also, the impact on

Availability when a new entity, namely the ISO, assumes Operational Control of the grid is unknown. Thus, it is the position of the ISO Maintenance Standards task force that the Availability performance monitoring system will be implemented and used to gauge Availability performance beginning on the ISO Operations Date. However, the system needs to be used and updated during a five year phase in period to be considered for use in a program of incentives and penalties for Availability performance.

Availability is a function of several variables including Transmission Facility Maintenance, capital improvements, and improvements in restoration practices. If a PTO is exercising a reasonable level of Maintenance, yet the Availability performance of a Voltage Class or individual Transmission Line Circuit is inadequate for the purposes of the ISO grid, then capital improvements or improvements in restoration practices may lead to greater Availability improvements than increased Maintenance. Therefore, assessing incentives and penalties on the basis of Availability as influenced by all of these variables may be a reasonable approach for influencing PTO's to improve the Availability of their Transmission Facilities where such improvements can be justified.

3. TRANSMISSION FACILITIES COVERED BY THE ISO MAINTENANCE STANDARDS

All Transmission Facilities transferred to the ISO, pursuant to the Transmission Control Agreement, shall be maintained in accordance with the ISO Maintenance Standards.

4. AVAILABILITY STANDARD

4.1. Introduction

The ISO shall monitor and measure each PTO's Availability for the Transmission Line Circuits under ISO Operational Control. The ISO shall use an Availability measurement system which consists of two primary components: 1) measures of the annual performance of each Voltage Class based on the performance of each of the Transmission Line Circuits comprising the Voltage Class, i.e. the Availability Measures; and 2) a set of threshold performance criteria for each Voltage Class, i.e. Availability Measure Targets. The Availability Measure Targets will be used to gauge the adequacy of the PTO's annual performance for each Voltage Class. Each PTO shall make an annual report to the ISO within 90 days from the end of each calendar year that describes its compliance with the Availability Measure Targets. In its report to the ISO, supporting data based on Outage$^{(IMS)}$ records shall be included, justifying the Availability Measures reported for each Voltage Class.

4.2. Availability Measures

4.2.1. Calculation of Availability Measures for Individual Transmission Line Circuits

The calculation of the Availability Measures will be performed utilizing Outage$^{(IMS)}$ data through December 31 of each year. Separate Forced Outage$^{(IMS)}$ frequency and accumulated Forced Outage$^{(IMS)}$ duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each

Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Outage data for the calendar year in question.

Forced Outage$^{(IMS)}$ Frequency:

The Forced Outage$^{(IMS)}$ frequency (f_{ik}) of the ith Transmission Line Circuit shall equal the total number of Forced Outages$^{(IMS)}$ that occurred on the ith Transmission Line Circuit during the calendar year k. See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages$^{(IMS)}$ on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage$^{(IMS)}$ with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage$^{(IMS)}$ and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e. 61 seconds or more, followed by another Forced Outage$^{(IMS)}$, then these should be counted as two Forced Outages$^{(IMS)}$. Multiple Forced Outages$^{(IMS)}$ occurring as a result of a single event should be handled as multiple Forced Outages$^{(IMS)}$ only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage$^{(IMS)}$.

2. If a Transmission Line Circuit, e.g. a new Transmission Line Circuit, is only in service for a portion of a year, the Forced Outage$^{(IMS)}$ frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire year, i.e. the Outage$^{(IMS)}$ data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage$^{(IMS)}$ Duration:

The accumulated Forced Outage$^{(IMS)}$ duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year k:

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages$^{(IMS)}$ (total number of Forced Outage$^{(IMS)}$ minutes) for the ith Transmission Line Circuit having a Forced Outage$^{(IMS)}$ frequency (f_{ik}) greater than zero for the calendar year k.

f_{ik} = Forced Outage$^{(IMS)}$ frequency as defined above for calendar year k.

o_{ijk} = duration in minutes of the j^{th} Forced Outage$^{(IMS)}$ which occurred during the k^{th} calendar year for the i^{th} Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages$^{(IMS)}$ shall be capped as described in Section 4.2.2. "Capping of Forced Outage$^{(IMS)}$ Duration" for the purposes of calculating the Availability Measures . In addition, certain types of events/Outages shall be excluded from the calculations of the Availability Measures as described in Section 4.2.3 "Excluded Events".

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Outage$^{(IMS)}$ data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO the PTO shall provide recommendations regarding how the Availability Measures and Availability Measure Targets should be modified to ensure they remain consistent with the modified Transmission Line Circuit identification or Outage$^{(IMS)}$ data reporting scheme, and that they provide an appropriate gauge of performance.

4.2.2. Capping of Forced Outage$^{(IMS)}$ Durations

The durations of individual Forced Outages$^{(IMS)}$ which exceed 72 hours (4320 minutes) shall each be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage$^{(IMS)}$ duration.

4.2.3. Excluded Events

The following types of events/Outages shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages which are scheduled, reviewed and approved by the ISO in accordance with the Transmission Control Agreement, and

- Forced Outages(IMS) which: 1) were caused by events outside the PTO's system including those Outages which originate in other TO systems, other electric utility systems, or customer equipment, and 2) those Forced Outages(IMS) which can be demonstrated to have been caused by earthquakes.

4.3. Targets for Availability Performance

The Availability Measure Targets described herein shall be phased in over a period of five years beginning on the ISO Operations Date. The adequacy of each PTO's Availability performance shall be monitored through the use of charts on which are plotted indices reflecting annual Availability performance. These charts, called control charts as shown in Figure 4.3.1, are defined by a horizontal axis with a scale of years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability performance for each Voltage Class within each PTO's system:

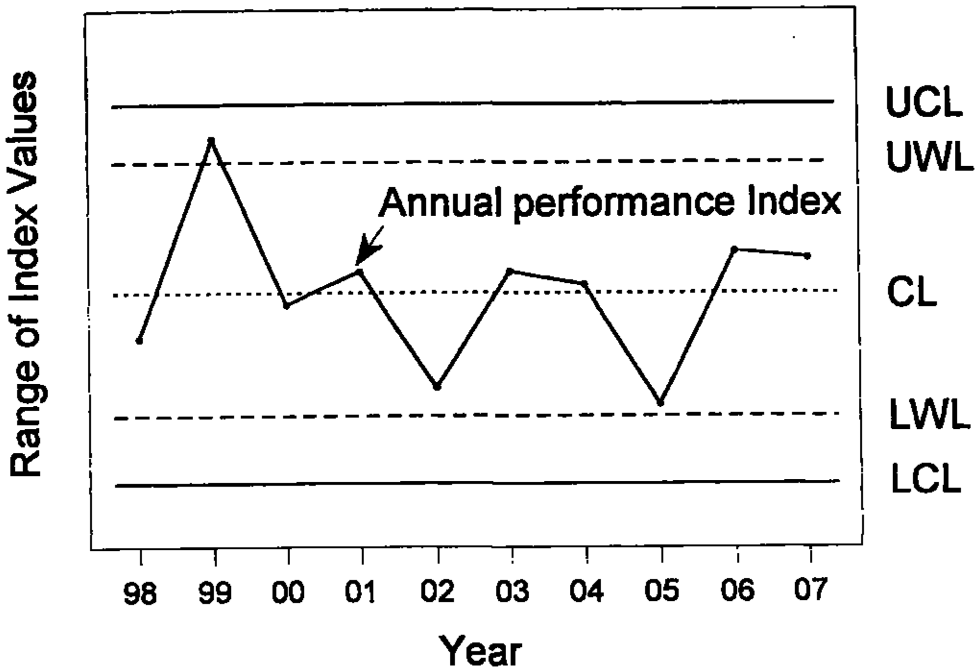

Figure 4.3.1 Sample Control Chart

- Index 1: Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits.
- Index 2: Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS).
- Index 3: Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS).

The control charts incorporate a center line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages(IMS), the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section 4.3.2. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the Normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number("seed") for it's random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section 4.3.3.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. Maintenance procedures recommended by the MCC and approved by the ISO Governing Board will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply.More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the MCC and approved by the ISO Governing Board for use in creating the control charts .

4.3.1. Calculations of Annual Availability Performance Indices for Individual Voltage Classes

Separate annual Availability performance indices shall be calculated for each Voltage Class and PTO as described below utilizing the Availability Measures discussed in Section 4.2.

Annual Average Forced Outage(IMS) Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k}\sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages(IMS) /Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class in calendar year k. See Note 2, Section 4.2.1.

f_{ik} = frequency of Forced Outages(IMS) for the i^{th} Transmission Line Circuit as calculated in accordance with Section 4.2.1 for calendar year k.

Annual Average Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS) (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}}\sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of Forced Outages(IMS) for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages(IMS) during the calendar year k.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage(IMS) frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

d_{ik} = accumulated duration of Forced Outages(IMS) for the i^{th} Transmission Line

Circuit having a Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) greater than zero for calendar year k as calculated in accordance with Section 4.2.1.

<u>Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$ (Index 3):</u>

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages$^{(IMS)}$ for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class for calendar year k. See Note 2, Section 4.2.1.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage$^{(IMS)}$ frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

4.3.2. Development of Limits for Performance Control Charts

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage$^{(IMS)}$ Frequency for All Transmission Line Circuits, Annual Average Accumulated Forced Outage$^{(IMS)}$ Duration for Transmission Line Circuits with Forced Outages$^{(IMS)}$, and Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$) on which the annual Availability performance indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Outage$^{(IMS)}$ data for the ten year period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. In the event that a PTO does not have reliable, continuously recorded Outage$^{(IMS)}$ data for this 10 year period, the PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, the PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO prior to February 1, 1998, or within 30 days after a TO becomes a PTO. The ISO shall periodically review the control chart limits and appropriately modify them when necessary in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

4.3.2.1. CLs

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability performance indices described in Section 4.3.1 except that the period for which data are to be included in the calculations is expanded from a single calendar year to the ten years, unless a shorter period is justified by the PTO, for the period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. To account for this change a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

CL for Annual Transmission Line Circuit Forced Outage(IMS) Frequency

$$CL_{fvc} = \sum_{k=1}^{Y} \sum_{i=1}^{N_k} f_{ik} \,/\, (\sum_{k=1}^{Y} N_k)$$

where

CL_{fvc} = center control line value for the Forced Outage(IMS) frequencies for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

Y = number of years prior to the ISO Operations Date (or the date a TO becomes a PTO) for which the PTO has reliable, continuously recorded Outage(IMS) data. Y=10 is preferred.

CL for Annual Accumulated Forced Outage(IMS) Duration for those Transmission Line Circuits with Forced Outages(IMS)

$$CL_{dvc} = \sum_{k=1}^{Y}\sum_{i=1}^{N_{o,k}} d_{ik} / (\sum_{k=1}^{Y} N_{o,k})$$

where

CL_{dvc} = center control line value for accumulated Forced Outage(IMS) duration for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date (or the date a TO becomes a PTO) in which the Forced Outage(IMS) frequency (f_{ik}) was greater than zero.

CL for Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)

$$CL_{Pvc} = \frac{\sum_{k=1}^{Y} (N_k - N_{o,k})}{\sum_{k=1}^{Y} N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages(IMS) for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

4.3.2.2. UCLs, LCLs, UWLs and LWLs

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages(IMS) for Five or More Years

The UCLs , UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages(IMS) shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each years development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of lines per year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process, will be repeated 10,000 times in order to create a column of sampling means from the historical data base. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL(99.75), a LCL(0.25) a UWL(97.5), and a LWL(2.5). Thus, for one cycle, the limits are determined by resampling from the historical data base, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get 10 values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index 2 forming means for the median number of lines with Forced Outages(IMS) in this Voltage Class for the time period being evaluated. See **Bootstrapping - A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the Bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per year with a history of ten years. Furthermore, assume that about 15 Transmission Line Circuits per year experience Forced Outages. Therefore, there are 10 x 15 = 150 Forced Outage(IMS) durations available for bootstrap sampling. Place these 150 Forced Outage(IMS) durations in a column, say "outdur"... in a specified order . The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage(IMS) duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest to largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 lines over the ten years using the formulas in Section 4.3.2.1. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

<u>UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes</u>

When data for less than four Transmission Line Circuits with Forced Outages(IMS) are available per year in a Voltage Class for fewer than five years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages(IMS) for five or more years. For example, if a Voltage Class has only two Transmission Line Circuits per year for five years, the data base will consist of 2*5 = 10 accumulated Forced Outage(IMS) durations assuming both Transmission Line Circuits experience a Forced Outage(IMS) or more per year. Resampling two values from the column of 10 yields only 10**2 = 100 possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data 10,000/100 = 100 times.

For the general case, let M = the number of accumulated Forced Outage$^{(IMS)}$ durations (or Forced Outage$^{(IMS)}$ frequencies) from the historical data base. If n is the median number of Transmission Line Circuits per year, there are M**n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing U enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e. at the 99.75, 0.25, 97. 5 and 2. 5 percentiles, respectively).

<u>UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Lines is > 125</u>

According to standard procedures for proportion control charts for voltage classes where the median number of lines in service is greater than 125 for any given year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the kth year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{Pvc} + 3S_{Pvc,k} \qquad LCL = CL_{Pvc} - 3S_{Pvc,k}$$

UWL and LWL are calculated by replacing the "3" above with a "2".

and

$$S_{Pvc,k} = \sqrt{CL_{Pvc}(1 - CL_{Pvc})/N_k}$$

where

$S_{Pvc,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages$^{(IMS)}$ for each (kth) year of the Y years prior to the ISO Operations Date, or the date a TO becomes a PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of Lines is less than or equal to 125 and greater than or equal to six.

The UCLs, LCLs, UWLs, and LWLs for the control charts for each voltage class shall be based on exact binomial probabilities for those voltage classes having equal to or more than six but less than or equal to 125 median transmission lines per year. A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL contains about 99.5% and the UWL and LWL contains about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

Where

P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas(i.e. P_2 = 0.9975 in the UCL formula and =0.025 in the LWL formula)

P_1 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas(e.g. if $P_1 = 0.74$ and is closest to the 99.75 percentile value and represents the 99 percentile then $P_1 = 0.74$ should be used in the UCL formula).

P_3 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas(e.g. if $P_3 = 0.82$ and is closest to the 99.75 percentile value and represents the 99.85 percentile then $P_3 = 0.82$ should be used in the UCL formula).

X_1 = The number of lines with no outages associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas.(e.g. If $P_1 = 0.74$ and represents the 99th percentile for the case where 78 lines didn't have any outages then $X_1 = 78$ should be used in the UCL formula).

n = The median number of lines that are in service in a given year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas

More information on the calculations of the proportion control chart limits is in the current ISO Transmission Facility Availability Performance Monitoring System Handbook.

4.3.3. Evaluation of Availability Performance

The control charts shall be reviewed annually in order to evaluate Availability performance. The annual performance evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual year, shifts in longer term performance, and trends in longer term performance.

<u>Tests</u>

- **Test 1:** The index value for the current year falls outside the UCL or LCL.
- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this says that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short term change or jump in the average level. Tests 2 and 4 are looking for long term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three year period. Together the four tests allow the ISO to monitor the availability performance of a Voltage Class for a PTO.

If none of these tests indicates that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table 4.3.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that year if necessary. However, it is suggested that unless the number of lines changes by more than 30% from the previous year, the use of the median number of lines should continue. Consider an example. Suppose after the control chart has been prepared for a Voltage Class, next year's data arrive with the number of lines 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that year.

For the special case where only one Transmission Line Circuit has a Forced Outage[(IMS)] in a Voltage Class during a year, the assessment process for Index 2 is as follows. If Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information on the individual and moving range control charts can be found in the user manuals of the statistical software approved by the ISO for use in creating the control charts

If the ISO deems that the Availability Measure Targets should be modified, they shall be modified in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

Table 4.3.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test		Performance Status Indicated by Test Results	
	Number	Results	Improvement	Degradation
Annual Average Forced Outage$^{(IMS)}$ Frequency	1	value is above the UCL		✓
		value is below the LCL when LCL>0	✓	
	2	v1 or more consecutive values above the CL		✓
		v2 or more consecutive values below the CL	✓	
	3	2 out of 3 values above the UWL		✓
		2 out of 3 values below the LWL	✓	
	4	6 consecutive values increasing		✓
		6 consecutive values decreasing	✓	
Annual Average Accumulated Forced Outage Duration	1	value is above the UCL		✓
		value is below the LCL when LCL>0	✓	
	2	v1 or more consecutive values above the CL		✓
		v2 or more consecutive values below the CL	✓	
	3	2 out of 3 values above the UWL		✓
		2 out of 3 values below the LWL	✓	
	4	6 consecutive values increasing		✓
		6 consecutive values decreasing	✓	
Annual Proportion of Transmission Line Circuits with No Forced Outages	1	value is above the UCL	✓	
		value is below the LCL when LCL>0		✓
	2	v1 or more consecutive values above the CL	✓	
		v2 or more consecutive values below the CL		✓
	3	2 out of 3 values above the UWL	✓	
		2 out of 3 values below the LWL		✓
	4	6 consecutively increasing values	✓	
		6 consecutively decreasing values		✓

4.4. Outage(IMS) Data Reporting

All Outages which interrupt the flow of power on PTO Transmission Facilities under the ISO's Operational Control shall be reported by the PTO to the ISO. Outage(IMS) reports shall include the date, start time, end time, affected Transmission Facility, and the probable cause of the Outage(IMS) if known.

5. ISO MAINTENANCE GUIDELINES AND PTO MAINTENANCE PRACTICES

5.1. Introduction

The ISO with due consideration for the recommendations of the Maintenance Coordination Committee shall establish, revise as needed, and maintain guidelines for Transmission Facilities Maintenance as described in Section 5.2 of this document. These ISO Maintenance Guidelines shall be followed by each PTO in preparing a written description of, and updating as necessary, its PTO Maintenance Practices which may be performance-based, time-based, or both, as may be appropriate for each Transmission Facility under the ISO's Operational Control. The PTO Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including technological innovations and facility importance.

5.2. ISO Maintenance Guidelines for Preparation of PTO Maintenance Practices

5.2.1. Transmission Line Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the following transmission line Maintenance activities:

a) Patrol/Inspection

- Routine
- Detailed
- Emergency

b) Vegetation Management/Right-of-Way Maintenance

As may be appropriate for the specific facilities and equipment under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail Maintenance activities for various attributes of the transmission lines including, but not limited to:

- Structures: wood pole, lattice steel, tubular steel, and concrete pole
- Guys/Anchors
- Foundations
- Insulators
- Conductor and Shield Wire
- Conductor and Shield Wire Clearances
- Hardware and Fittings
- Disconnects/Pole-top Switches
-
- Encroachments/Unauthorized Attachments
- Underground Transmission Components

5.2.2. Station Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the Maintenance of the following equipment and attributes of Stations:

- Circuit Breakers
- Insulators/Bushings/Arrestors
- Transformers
- Regulator
- Disconnect Switches
- Metering
- Battery Systems
- Reactive Devices

- Relaying
- Communication Facilities
- Station Auxiliary Equipment
- Direct Current Transmission Components
- Structures/Foundations

As may be appropriate for the specific equipment in and configurations of the PTO's Stations under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail various Maintenance activities for the attributes and potential conditions of the Stations including, but not limited to:

- Visual Inspection of/for: fences and grounds, vegetation, clearances, tracking, abnormal heating, cracks/chips, noise, leaks, blown fuses, and bulging of equipment cases
- Oil Containment
- Insulation Mediums
- Equipment Contacts
- Mechanical Timing
- Contamination Control
- Testing and Calibration
- Cooling Systems
- Measuring Devices
- Lubrication and Overhaul of Moving Parts

5.2.3. Descriptions of PTO Maintenance Practices

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The PTO's Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms which may be required for the activity. Where appropriate, the PTO's

Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility or component. Where appropriate, the PTO's Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission Facilities.

5.3. Review and Adoption of PTO Maintenance Practices

5.3.1. Initial Adoption of PTO Maintenance Practices

5.3.1.1. Submittal of Information by the Prospective PTOs to the ISO

Each prospective PTO shall provide the ISO with information concerning its PTO Maintenance Practices pursuant to Section 5.2 of this Appendix C. This information shall be prepared so as to be easily interpreted by the ISO and shall provide sufficient detail to assess the adequacy and reasonableness of the PTO Maintenance Practices, using the criteria referenced in Section 14.1 of the Transmission Control Agreement.

5.3.1.2. Review of the PTO Maintenance Practices by the ISO

The ISO shall review the information provided pursuant to Section 5.3.1.1 of this Appendix C and may provide to a PTO a recommendation for an amendment to the PTO Maintenance Practices in question by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. To the extent there are no recommendations, the PTO Maintenance Practices will be adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

Any agreement, in respect of PTO Maintenance Practices, reached between the ISO and a prospective PTO prior to the ISO Operations Date shall be adopted by the ISO for purposes of this Section 5.3.1.

5.3.2. Proposals for Amendments to the PTO Maintenance Practices

5.3.2.1. Amendments Proposed by the ISO

The ISO shall periodically review each PTO's Maintenance Practices having regard to the ISO Maintenance Standards, as amended and revised from time to time pursuant to Sections 7 and 8 of this Appendix C. Following such a review, and after considering the Section 348 Criteria, the ISO may recommend an amendment of PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with 5.3.3 of this Appendix C. Except as provided in Section 5.3.3.4 of this Appendix, the effective date shall be no earlier than 30 days from the date of such notice.

5.3.2.2. Amendments Proposed by a PTO

A PTO may provide to the ISO its own recommendation for an amendment to its PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. The effective date shall be no earlier than 30 days from the date of such notice.

5.3.3. Disposition of Recommendations

5.3.3.1. If the ISO or a PTO makes a recommendation to amend the PTO Maintenance Practices of a PTO, as contemplated in Sections 5.3.1 or 5.3.2 of this Appendix C, the other Party shall have 30 days to provide a notice to the recommending party, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not agree with the recommended amendment. If it fails to provide such notice of disagreement, the recommended amendment shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified in the notice of the recommended amendment, which date shall be no earlier than 30 days from the date of issuance of such notice of amendment.

5.3.3.2. If a PTO makes a recommendation to amend its PTO Maintenance Practices, and if the ISO provides notice within the 30 days specified in the first paragraph of this Section 5.3.3, pursuant to Section 26.1 of the Transmission Control Agreement, that the ISO, having regard for the Section 348 Criteria, does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing PTO Maintenance Practices shall be retained. Either Party may, however, seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.3. If the ISO makes a recommendation to amend the PTO Maintenance Practices of a PTO, the PTO Maintenance Practices, as amended pursuant to the ISO recommendation, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified by the ISO in its notice of recommended amendment. If the PTO gives notice of a disagreement within the 30 days specified in the first paragraph of this Section 5.3.3, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If a resolution is not reached, either Party may seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment, and the ISO shall not unreasonably withhold its consent to such a request, having regard to the Section 348 Criteria. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.4. If the ISO determines in its judgment, after considering the Section 348 Criteria, that prompt action is required to avoid a substantial risk to safety or reliability, it may direct a PTO to implement certain temporary maintenance activities in a period of less than 30 days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any such maintenance practice advisories shall specify why implementation solely under Section 5.3.3.3 is not sufficient to avoid a substantial risk to safety or reliability including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. If time permits, the ISO shall consult with the relevant PTO before issuing a maintenance practice advisory. Upon receiving such an advisory, a PTO shall implement the temporary maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary maintenance activities as fully as possible. All such maintenance practice advisories shall cease to have effect in 90 days after issuance or such earlier period as the ISO provides in its notice. Renewal or extension of such temporary maintenance requirements beyond 90 days shall require a recommendation process pursuant to Section 5.3.3.2 or Section 5.3.3.3 of this Appendix.

5.3.3.5. Nothing in this Transmission Control Agreement shall be construed to limit the ISO's authority under Public Utilities Code Section 348 to adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under ISO control.

5.4. Qualifications of Personnel

All Maintenance of Transmission Facilities under the ISO's Operational Control shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

The four elements of the ISO's requirements for Maintenance record keeping and reporting are as follows:

a) The PTO will maintain records of its Maintenance activities, as set forth in Section 6.1.
b) The PTO will provide certain Maintenance records to the ISO, as set forth in Section 6.2.
c) The PTO will allow the ISO to visit Transmission Facilities, as set forth in Section 6.3.
d) The PTO will make records for Maintenance activities available to the ISO, as set forth in Section 6.4.

In addition, the Maintenance Coordination Committee shall annually review the requirements of this section of the ISO Maintenance Standards and shall seek to standardize reasonable record keeping, reporting and information-sharing requirements sufficient to support ISO regulatory reporting needs.

6.1. The PTO Will Maintain Records of its Maintenance Activities

The PTO shall maintain records demonstrating compliance with each element of the PTO Maintenance Practices. The PTO's Maintenance records shall be maintained for five years, or for one year after specific corrective Maintenance activities identified by the PTO are completed, whichever is longer.

Each PTO's inspection records shall, at a minimum, identify the inspector, the Transmission Facility inspected, the inspection date(s), the findings of the inspection, recommended Maintenance activities, and the priority of the Maintenance recommendations.

Each PTO's Maintenance records shall, at a minimum, identify the person responsible for performing the Maintenance, the date of the Maintenance, the Transmission Facility maintained, and a description of the Maintenance that was performed.

6.2. The PTO Will Provide Certain Maintenance Records to the ISO

By the end of the third year of operation of the ISO, the ISO and PTO's shall develop and implement a standard Maintenance reporting system based on the recommendations of the Maintenance Coordination Committee. Until the standard Maintenance reporting system is implemented, the PTO shall provide the ISO, on an annual basis, records for substantial Maintenance as limited by the following list:

a) Transmission Line Maintenance

- Patrol/Inspection
- Vegetation Management/Right-of-way Maintenance
- Structures: Wood pole, lattice steel, tubular steel, concrete pole

- Insulators (Contamination Control)

b) Station Maintenance

- Circuit Breakers
- Transformers
- Insulators/Bushings/Arrestors (Contamination Control)
- Regulators
- Relaying

If the PTO maintains records in a manner that includes additional information, such records may be submitted in that manner.

6.3. The PTO Will Allow the ISO to Visit Transmission Facilities

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement.

6.4. The PTO Will Make Records for Maintenance Activities Available to the ISO

The PTO shall make all Maintenance records for a Voltage Class available to the ISO upon the request of the ISO if the annual evaluation of performance per Section 4.3.3 demonstrates degradation in the PTO's Availability performance. Upon identification of degradation, the PTO's reporting of Maintenance data to the ISO shall continue until a subsequent year's annual performance returns to a non-degraded level.

If a review of available records by the ISO indicates inconsistencies from the PTO Maintenance Practices relating to a specific activity, then the ISO may request that the PTO provide further documentation and explanation related to those Maintenance activities.

7. MAINTENANCE COORDINATION COMMITTEE

7.1. Maintenance Coordination Committee Functions

The ISO shall seek to establish and then appropriately convene a Maintenance Coordination Committee for the purposes of periodically conveying information, seeking input from other PTOs and interested stakeholders regarding ISO Maintenance Standards as well as making recommendations with respect to proposed amendments and revisions of the ISO Maintenance Standards.

7.2. Consensus

Although the role of the Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members, and promulgate practices, standards and protocols consistent with relevant laws and regulations.

8. REVISION OF ISO MAINTENANCE STANDARDS

The ISO, PTO's, or any interested stakeholder may submit proposals to amend or revise the ISO Maintenance Standards. Any change proposal shall be submitted to the Maintenance Coordination Committee for consideration in accordance with Section 7.0, "Maintenance Coordination Committee," of this document. Recommendations for revisions of the ISO Maintenance Standards shall be submitted by the Maintenance Coordination Committee to the ISO for approval.

9. INCENTIVES AND PENALTIES

Any incentives and penalties relating to this Appendix shall be established in accordance with the Transmission Control Agreement, the ISO Tariff and ISO Protocols after consultation between the PTO and the ISO, and approval by the FERC. No incentives, penalties or sanctions may be imposed relating to this Appendix unless a

Schedule providing for such incentives, penalties or sanctions has first been filed with and made effective by the FERC. Nothing in this Appendix shall be construed as waiving the rights of the PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the PTO.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain its Transmission Facilities that are under the Operational Control of the ISO in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable protocols, laws, and regulations, in order to achieve the Availability Measure Targets set by the ISO.

10.1 SAFETY

It is of paramount importance that the PTO ensure the safety of personnel, and the public in performing these Maintenance duties and that the ISO operate the system in a manner which is compatible with the priority of ensuring safety. The PTO shall ensure the safety of personnel and the public in accordance with jurisdictional agency regulations and ensure the reliability of the system in accordance with CAISO Maintenance Standards. In the event there is conflict between the safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any disputes between the ISO and PTO regarding issues related to the Maintenance, and Availability of Transmission Facilities under the Operational Control of the ISO shall be resolved in accordance with the Section 15 of the Transmission Control Agreement.

TRANSMISSION CONTROL AGREEMENT

APPENDIX D

Master Definitions Supplement

Actual Adverse Tax Action A plan, tariff provision, operating protocol, action, order, regulation or law issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, that likely adversely affects the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO or that, with the passage of time, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, no Actual Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Actual Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.

Adverse Tax Action Determination A determination by a Tax Exempt Participating TO, as supported by (i) an opinion of its (or its joint action agency's) nationally recognized bond counsel, or (ii) the IRS (e.g., through a private letter ruling received by a Tax Exempt Participating TO or its joint action agency), that an Impending Adverse Tax Action or an Actual Adverse Tax Action has occurred.

AGC (Automatic Generation Control) Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

Ancillary Services Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.

Applicable Reliability Criteria The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.

Applicants	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.
Approved Maintenance Outage	A Maintenance Outage which has been approved by the ISO through the ISO Outage Coordination Office.
Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Business Day	A day on which banks are open to conduct general banking business in California.
Congestion	A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously. "Congested" shall be construed accordingly.
Congestion Management	The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.
Control Area	An electric power system (or combination of electric power systems) to which a common AGC scheme is

applied in order to: i) match, at all times, the power output of the Generating Units within the electric power system(s), plus the Energy purchased from entities outside the electric power system(s), minus Energy sold to entities outside the electric power system, with the Demand within the electric power system(s); ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and iv) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

CPUC — The California Public Utilities Commission, or its successor.

Critical Protective System — Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.

Day-Ahead Market — The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO, the PX and other Scheduling Coordinators and which closes with the

ISO's acceptance of the Final Day-Ahead Schedule.

Demand The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.

Eligible Customer (i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.

EMS (Energy Management System) A computer control system used by electric utility dispatchers to monitor the real time performance of the various elements of an electric system and to control Generation and transmission facilities.

Encumbrance A legal restriction or covenant binding on a Participating

TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.

End-Use Customer or **End-User** — A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.

Energy — The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.

Entitlements — The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.

Existing Contracts — The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

Existing Rights — Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.

Facilities Study Agreement — An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study.

Facility Study — An engineering study conducted by a Participating TO to determine required modifications to the Participating TO's transmission system, including the cost and scheduled completion date for such modifications that will be required to provide needed services.

FERC — The Federal Energy Regulatory Commission or its successor.

FIITC (Firm Import Interconnection Transmission Capacity) — The amount of firm transmission capacity in MW associated with transmission facilities owned by a Participating TO or contracted to the Participating TO under an Existing Contract, which allows Generating Units that are not directly interconnected with that Participating TO's transmission or distribution system to deliver Energy to that Participating TO. For each month of the Self-Sufficiency Test Period, FIITC shall include the maximum amount of requirements and bundled power sale capacity purchased by the Participating TO from the transmission owner to which it is physically interconnected during the hour in which the Monthly Peak Load of the Participating TO occurs.

Forced Outage An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.

FPA Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.

Generating Unit An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is:

(a) located within the ISO Control Area;

(b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and

(c) that is capable of producing and delivering net

Energy (Energy in excess of a generating station's internal power requirements).

Generation Energy delivered from a Generating Unit.

Generator The seller of Energy or Ancillary Services produced by a Generating Unit.

Good Utility Practice Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Hour-Ahead Market The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO, the PX and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the

ISO's acceptance of the Final Hour-Ahead Schedule.

Hydro Spill Generation Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.

Impending Adverse Tax Action A proposed plan, tariff, operating protocol, action, order, regulation or law that, if issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, that with respect to a proposed federal law, such proposed law must first have been approved by (i) one of the houses of the United States Congress and (ii) at least one committee or subcommittee of the other house of the United States Congress; provided further, however, no Impending

Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Impending Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.

Interconnection Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational

	Control of the Participating TO's portion of the ISO Controlled Grid.
<u>Interconnection Agreement</u>	A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.
<u>IRS</u>	<u>The United States Department of Treasury, Internal Revenue Service, or any successor thereto.</u>
<u>ISO (Independent System Operator)</u>	The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
<u>ISO ADR Procedures</u>	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
<u>ISO Code of Conduct</u>	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in Exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in Exhibit B to the ISO bylaws.
<u>ISO Control Center</u>	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.
<u>ISO Controlled Grid</u>	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the

ISO's Operational Control.

ISO Governing Board — The Board of Governors established to govern the affairs of the ISO.

ISO Grid Operations Committee — A committee appointed by the ISO Governing Board pursuant to Article IV, Section 4 of the ISO bylaws to advise on additions and revisions to its rules and protocols, tariffs, reliability and operating standards and other technical matters.

ISO Operations Date — The date on which the ISO first assumes Operational Control of the ISO Controlled Grid.

ISO Outage Coordination Office — The office established by the ISO to coordinate Maintenance Outages in accordance with Section 2.3.3 of the ISO Tariff.

ISO Protocols — The rules, protocols, procedures and standards promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.

ISO Register — The register of all the transmission lines, associated facilities and other necessary components that are at the relevant time being subject to the ISO's Operational Control.

<u>**ISO Tariff**</u>	The California Independent System Operator Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
<u>**Load**</u>	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
<u>**Local Furnishing Bond**</u>	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
<u>**Local Furnishing Participating TO**</u>	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
<u>**Local Regulatory Authority**</u>	The state or local governmental authority responsible for the regulation or oversight of a utility.
<u>**Local Reliability Criteria**</u>	Reliability criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
<u>**Maintenance Outage**</u>	A period of time during which an Operator takes its facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment.

Market Participant	An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.
Municipal Tax Exempt TO	A Transmission Owner that has issued Municipal Tax Exempt Debt with respect to any transmission facilities, or rights associated therewith, that it would be required to place under the ISO's Operational Control pursuant to the Transmission Control Agreement if it were a Participating TO.
NERC	The North American Electric Reliability Council or its successor.
Nomogram	A set of operating or scheduling rules which are used to

	ensure that simultaneous operating limits are respected, in order to meet NERC and WSCC operating criteria.
Non-Converted Rights	Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.
Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
NRC	The Nuclear Regulatory Commission or its successor.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.
Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
Operator	The operator of facilities comprised in the ISO Controlled Grid or Reliability Must-Run Units.

<u>Outage</u>	Disconnection or separation, planned or forced, of one or more elements of an electric system.
<u>Participating Generator</u>	A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid and which has undertaken to be bound by the terms of the ISO Tariff.
<u>Participating TO</u>	A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA.
<u>Physical Scheduling Plant</u>	A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating

components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.

PMS (Power Management System) The ISO computer control system used to monitor the real time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.

Preferred Schedule The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The

Preferred Schedule will be balanced with respect to Generation, Transmission Losses, Load and trades between Scheduling Coordinators.

Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Regulatory Must-Run Generation	Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements, or the requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as

it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.

Reliability Criteria	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
Reliability Must-Run Unit	A Generating Unit which is the subject of the contract between the Generator and the ISO under which, in return for certain payments, the ISO is entitled to call upon the owner to run the unit when required by the ISO for the purposes of the reliable operation of the ISO Controlled Grid.
RTG (Regional Transmission Group)	A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.
Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical,

non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.

Self-Sufficiency or **Self-Sufficient**	A Participating TO for which the sum of its Dependable Generation and its FIITC is greater than or equal to its Monthly Peak Load.
Settlement Account	An account held at a bank situated in California, designated by a Scheduling Coordinator or a Participating TO pursuant to the Scheduling Coordinator's SC Agreement or in the case of a Participating TO, Section 2.2.1 of the TCA, to which the ISO shall pay amounts owing to the Scheduling Coordinator or the Participating TO under the ISO Tariff.
System Emergency	Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system

elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.

System Planning Studies	Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.
System Reliability	A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax-Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and

whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.

UDC (Utility Distribution Company) — An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

Uncontrollable Force — Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, breakage, or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence.

Voltage Support — Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.

WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange among the ISO, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.
Wheeling Out	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Wheeling Through	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located outside the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Withdraw for Tax Reasons or Withdrawal for Tax Reasons	In accordance with Section 3.4 of this Agreement, withdrawal from this Agreement, or withdrawal from the ISO's Operational Control of all or any portion of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the

Tax Exempt Debt that is the subject of an Impending Adverse Tax Action or an Actual Adverse Tax Action.

WSCC (Western System Coordinating Council) The Western Systems Coordinating Council or its successor.

TRANSMISSION CONTROL AGREEMENT

APPENDIX E

Nuclear Protocols

DIABLO CANYON NUCLEAR POWER PLANT
UNITS 1 & 2

REQUIREMENTS FOR OFFSITE
POWER SUPPLY OPERABILITY
REVISION 1

DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

OVERVIEW

The DCPP Operating License and Technical Specifications require two physically independent sources (not necessarily on separate right of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both sources is acceptable. Each of these sources shall be designed to be available in sufficient time following a loss of all DCPP onsite alternating current power supplies and the other offsite electric power circuit. One of these sources shall be designed to be available within a few seconds following a loss-of-coolant accident. For DCPP, the sources available within seconds are the 230 kV grid interface and the second source is the 525 kV grid interface.

During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads (safety related and non-safety related) are transferred to the 230 kV grid. In addition DCPP has a delayed transfer capability to the 525 kV grid. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.

The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If either source of the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP units(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if either source is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition, which renders the offsite power unavailable for safe shutdown and emergency purposes.

In specific terms, the offsite power supply voltages (at the DCPP switchyards) must stay within the range of 207 kV to 240 kV and 525 kV to 545 kV under post accident operating conditions. During normal operation, the 230 kV voltage must maintain above 207 kV such that when DCPP transfers its load from the onsite source to the offsite source the voltage does not decrease below 207 kV. During normal operation, the 230 kV voltage at DCPP 230 kV switchyard should meet the 230 kV voltage requirements identified in PG&E Operating Instruction O-23. Otherwise, that offsite power source may be considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip does not impair the operability of the offsite power system. Therefore, following a trip of a DCPP unit (i.e., the unit breakers open) and assuming the other DCPP unit was already shutdown, the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the unit trip. If this condition cannot be met, then the offsite power source is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 kV and 230 kV grid must remain stable if both DCPP units trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the DCPP operating staff for Operability determination.

SPECIFIC REQUIREMENTS

Note: This section identifies the operational requirements for the DCPP offsite power supply. These requirements are part of the DCPP design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised as necessary. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPP unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to the ISO, PG&E and the DCPP operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements requires prior approval by PG&E.

1. Three transmission lines into the 500 kV DCPP switchyard and two lines into the 230 kV DCPP switchyard are normally in service. Any change that alters the performance capabilities of either offsite source at the applicable switchyard requires prior approval by PG&E (DCPP) and the ISO.

   No line may be removed from service at anytime without prior notification to the DCPP Operations Department. At least two independent sources of power, the 500 kV and the 230 kV systems, between the transmission network (grid) and DCPP switchyards shall be available at all times. PG&E System Operating Procedure, 0-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.

2. With both Diablo Canyon units off-line, the DCPP 500 kV and 230 kV offsite power source should be capable of providing 130 MVA (i.e. dual unit orderly shutdown) to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.

3. The minimum grid voltage at DCPP 230 kV switchyard shall be maintained at or above 230 kV for normal operation with all Los Padres 230 kV elements (See list below) in service. In the event of a system disturbance or line outage that can cause the DCPP voltage to dip below 230 kV, including the

trip of a DCPP unit, the grid voltage shall recover to 207 kV or above within 16 seconds.

Los Padres Area Major 230 kV Elements	Major 500 kV Elements
DCPP – Mesa Line	DCPP – Gates Line
Morro Bay – Mesa Line	DCPP - Midway Line #1 & #2 Line
Morro May – DCPP Line	
Morro Bay – Templeton Line	
Morro Bay - Midway Line #1 or #2 Line	
Morro Bay - Gates Line #2 Line	
Largest Los Padres area generator other than DCPP	
DCPP 230 kV capacitor banks	
Mesa 115 kV capacitor banks	

4. Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:

   a) The loss of two DCPP units.

   b) The loss of any generating unit on the PG&E grid.

   c) The loss of any major transmission circuit or intertie on the PG&E grid.

   d) The loss of any large load or block of load on the PG&E grid.

5. The maximum grid voltage at the DCPP 230 kV and 500 kV switchyards shall be maintained at or below 240 kV and 545 kV, respectively, unless required to preserve transmission network integrity.

6. The 500 kV system shall be maintained between 525 kV and 545 kV. Operation of DCPP is limited between 24.375 kV and 26.25 kV (i.e. 0.975 p.u. and 1.05 p.u.).

PG&E, in coordination with the ISO, shall perform and update system studies based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the DCPP offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition that renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPP operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPP switchyard voltages or otherwise unanalyzed render the offsite power supply Inoperable. DCPP operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPP) and the ISO.

System studies shall consider the interconnections between PG&E, and other utilities in the Western Electricity Coordinating Council (WECC) region.

7. In the event of a complete loss of the DCPP offsite power supply (i.e. both the 230 kV and 500 kV grid interfaces) both the ISO and PG&E shall establish the following restoration priorities:

    a) Highest possible priority shall be given to restoring power to the DCPP switchyards.

    b) Should incoming lines to the DCPP switchyards be damaged, highest priority shall be assigned to repair and restoration of at least one line into the DCPP switchyards.

    c) Repair crews engaging in power restoration activities for DCPP shall be given the highest priority for manpower, equipment, and materials.

    d) Formal programs and procedures shall be in place to effect items a), b), and c) above.

8. Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:

    a) At 59.65 Hz, E19 & E20 interruptible customers are tripped.

    b) PG&E complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

9. Patrol and inspection of PG&E transmission lines shall be performed in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice.

10. Line insulators between the plant and switchyard shall be washed by PG&E on an appropriate wash cycle during the wash season in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice to reduce line outages that may result from flashovers due to possible accumulated contamination.

11. Maintenance, testing and calibration of DCPP switchyard equipment and protective relays shall be performed in accordance with the current CAISO approved PG&E Electrical Station Maintenance Practice.

12. PG&E (DCPP) maintains a safety analysis for DCPP (Section 8.0, Electric Power of DCPP 1&2 Final Safety Analysis Update Report (FSAR)). PG&E (DCPP) is required by 10CFR50.71(e) to submit to the NRC periodic updates to the FSAR. The requirements contained in this Appendix E are documented in the FSAR. Any changes to these requirements, or the Bulk Power Transmission System Reliability criteria used as a basis for compliance with a requirement, shall be transmitted by both the ISO and PG&E (Transmission operator) to PG&E (DCPP) for prior approval.

These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.

~~DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY~~

~~OVERVIEW~~

~~During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads are transferred to an alternative source. The preferred immediate alternate source of electrical power for DCPP electric loads (safety-related and nonsafety-related) is the offsite power supply or 230kV grid In addition DCPP has a delayed 500 kV source. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.~~

~~The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP units(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable for safe shutdown and emergency purposes.~~

~~In specific terms, the offsite power supply voltage (at the DCPP switchyard) must stay within the range of 207 kV to 240kV under post-accident operating conditions During normal operation the voltage must be held enough above 207kV so that when DCPP transfers it's load from the onsite source to the offsite source the voltage does not decrease below 207kV. For normal operation with all lines in service the voltage must be above 211kV. During normal operation, the voltage~~

~~should be above 218kV. Otherwise the offsite power supply is considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a DCPP unit (i.e., the unit breakers open), the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the trip. If this condition cannot be met, then the offsite power supply in the pre trip condition is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 and 230 kV grid must remain stable if both DCPP units trip.~~

~~System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the DCPP operating staff for Operability determination.~~

~~SPECIFIC REQUIREMENTS~~

~~Note: This section identifies the operational requirements for the DCPP offsite power supply. These requirements are part of the DCPP design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised from time to time. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPP unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to PG&E and the DCPP operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by PG&E.~~

1. ~~Three transmission lines into the 500 kV switchyard and two lines into the 230 kV DCPP switchyard are normally in service. Any increase or decrease in the number of lines into the DCPP switchyard requires prior approval by PG&E.~~

   ~~No line may be removed from service at anytime without prior notification to the DCPP Operations Department. At least two independent sources of power, the 500 kV and the 230kV system between the transmission network (grid) and DCPP switchyards shall be available at all times. PG&E System Operating Procedure, 0-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.~~

2. ~~With both Diablo Canyon units off-line, the DCPP 500 and 230kV offsite power source should be capable of providing 105MW and 78 MVAR to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.~~

3. ~~The minimum grid voltage at DCPP switchyard shall be maintained at or above 218kV for normal operation with all lines in service. In the event of a system disturbance or line outage that can cause the voltage to dip below 218kV,~~

~~including the trip of a DCPP unit, the grid voltage shall recover to 207kV or above within 16 seconds.~~

4. ~~Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:~~

    ~~a) The loss of two DCPP units.~~

    ~~b) The loss of any generating unit on the PG&E grid.~~

    ~~c) The loss of any major transmission circuit or intertie on the PG&E grid.~~

    ~~d) The loss of any large load or block of load on the PG&E grid.~~

5. ~~The maximum grid voltage at the DCPP switchyard shall be maintained at or below 240kV. (References 10, 11)~~

6. ~~The normal operating voltage of the DCPP switchyard shall be maintained at 230 kV. The DCPP switchyard voltage shall not exceed 240kV unless required to preserve transmission network integrity.~~
7. ~~The 500 kV system shall be maintained between 510kV and 550kV. Operation of DCPP is limited between .97 p.u. and 1.05 p.u. Requests to operate above 1.01 p.u. shall be analyzed prior to implementation to assure viability of the 500kV and 230kV after a DCPP unit trip. If two of three 500 kV lines are out of service, spinning reserve must be available that is equal to the total of DCPP generation.~~

~~System studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions that could render offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPP operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPP switchyard voltages or otherwise unanalyzed, render the offsite power supply Inoperable. DCPP operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to PG&E. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be transmitted via letter to PG&E.~~

~~System studies shall consider the interconnections between PG&E, and other utilities in the Western States Coordinating Council (WSCC) region.~~

8. ~~In the event of loss of the DCPP offsite power supply:~~

~~Note: With regard to Station Blackout(SB 0) DCPP 1 &2 are 4 hour coping plants. The regulatory requirement is that DCPP be able to withstand a loss of all AC power (loss of offsite power plus loss of both Emergency Diesel Generators) for 4 hours. Therefore, at least one transmission line into the DCPP switchyard should be restored within 4 hours to prevent possible core damage.~~

~~a) Highest possible priority shall be given to restoring power to the DCPP switchyards.~~

~~b) Should incoming lines to the DCPP switchyards be damaged, highest priority shall be assigned to repair and restoration of at least one line into the DCPP switchyards.~~

~~c) Repair crews engaging in power restoration activities for DCPP shall be given the highest priority for manpower, equipment, and materials.~~

~~d) Formal programs and procedures shall be in place to effect items a), b), and c) above.~~

9. ~~Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:~~

    a) ~~At 59.75 Hz, A- 18 interruptible customers are tripped.~~

    b) ~~At 59. 1 Hz, PG&E system load shedding is initiated. Two 5% blocks (10%) of load is tripped at this frequency and at 0.2 Hz decrements until 50% of load has been tripped (10 5% blocks).~~

    c) ~~At 58.2 Hz the north and south 500 kV intertie lines are tripped to separate the PG&E system from SCE and the Northwest systems.~~

    d) ~~Thermal plants are equipped with 3 setpoint underfrequency relays that would cause underfrequency tripping to protect the turbines and generators from being damaged. The set points are:~~

    ~~58 Hz with 3-minute time delay~~
    ~~57 Hz with 1-minute time delay~~
    ~~55 Hz with 0.5 seconds time delay~~

    e) ~~Hydro generators are tripped last at 54.0 Hz with 1-minute time delay.~~

10. ~~PG&E Bulk Power Transmission System Reliability Criteria as described in the DCPP Updated Final Safety Analysis Report shall be maintained. Changes to the reliability criteria that could adversely impact grid reliability and availability as defined in this specification require prior approval of PG&E.~~

11. ~~PG&E transmission lines shall be patrolled annually to ensure that the physical and electrical integrity of transmission system components is maintained.~~

12. ~~Line insulators, pole hardware terminals, and tower hardware terminal within the first three miles from the Diablo switchyard shall be washed and inspected at least three times a year to reduce line outages that may result from flashovers due to possible accumulated contamination.~~

13. ~~Preventive maintenance, testing and calibration of DCPP switchyard circuit breakers and protective relays shall be performed as follows:~~

    ~~PG&E: 230kV & 500kV circuit breakers are inspected every 2 years and overhauled every 8 years. Transmission line relays are tested every 36 months.~~

    ~~Preventive maintenance and testing of DCPP switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of DCPP switchyard battery chargers and DC system components shall be performed every 3 months.~~

14. ~~Updates to applicable portions of Section 8.0, Electric Power of DCPP 1&2~~

~~Updated Final Analysis Report (UFSAR) shall be provided annually. These updates will be used by PG&E to prepare a UFSAR change submittal to the NRC. DCPP is required by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.~~

~~These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.~~

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised September 2, ~~January 5, 1998~~2002

OVERVIEW

The preferred source of electrical power for SONGS electrical loads (safety-related and nonsafety-related) is the ***offsite power supply*** or 230 kV grid. The offsite power supply is sometimes referred to as the ***preferred power supply*** in the regulatory documents.

The basic requirement for the offsite power supply is that it provides ***sufficient capacity and capability*** to safely shut down the reactor and to mitigate certain specified accident scenarios. When this condition is met, the offsite power supply is considered Operable with respect to the SONGS Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable to safely shutdown the units or to supply emergency electrical loads.

In specific terms, the offsite power supply voltage (at the SONGS switchyard) must stay within the range of 218 kV to 238 kV under all normal and plant accident (i.e. emergency shutdown or trip) conditions. Otherwise the offsite power supply is considered Inoperable. Since accident scenarios for which the plant is designed can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a SONGS unit (i.e., the unit breakers open), the SONGS switchyard voltage must recover to and be maintained at or above 218 kV within 2.5 seconds following the trip. If this condition cannot be met, then the offsite power supply is considered Inoperable, and action must be taken to shut down the operating SONGS unit(s). Even though these requirements apply at all times, this condition is primarily of concern when one SONGS unit is online and the other unit offline. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room for Operability determination.

The SONGS switchyard is made up of the SCE switchyard and the SDG&E switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

SPECIFIC REQUIREMENTS

Note 1: This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to SCE and the SONGS Control Room for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by SCE.

Note 2: Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.

1. Nine transmission lines into the SONGS switchyard are normally in service. Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval of SCE. (Reference 7)

   No line may be removed from service for greater than 30 days without prior notification to SCE. At least two independent transmission lines (one from SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8)

2. With both San Onofre units off-line, the SONGS offsite power source shall be ~~capable of providing 152 MW and 96 MVAR~~ capable of providing 158 MW and 96 MVAR to San Onofre for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions. (References 9, 10)

3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV. In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall recover to 218 kV or above within 2.5 seconds. (References 9, 10, 12, 13, 18)

4. The following initiating events shall not result in the loss of grid stability or availability:

   a. The loss of a San Onofre Unit (with the other unit already offline), or

   b. The loss of any generating unit on the SCE and SDG&E grids, or

   c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or

   d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids.

   (References 2, 3, 4, 8)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 238 kV. (References 10, 11, 18)

6. The normal operating voltage of the SONGS switchyard shall be maintained at 230 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18)

7. The limiting conditions for SONGS offsite power source operability are defined as follows:

   1. One SONGS unit is off- line, and
   2. One of the critical line (s) outages occurs (see list of the- lines below), and
   3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the referenced nomograms in the ~~ECC~~GCC Operating Procedure : SONGS Voltage~~, dated December 9, 1997~~ (Current revision).

   ~~Based on these nomograms and SONGS offline unit's mode status if the ECC, Grid Control Center (GCC), or ISO determines that the operating point is outside the applicable derated import nomogram line~~Based on these nomograms and SONGS offline unit's status, if the Grid Control Center or ISO determines that the operating point is outside the applicable derated nomogram line, they shall notify SONGS immediately that a particular transmission line is out of service, and the critical system conditions are sufficient to cause SONGS off site power source to be considered INOPERABLE; i.e., unable to support SONGS voltage at 218 kV if the remaining unit trips. SONGS Control Room will declare the offsite source inoperable (in anticipation of losing the second SONGS unit) and will declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period will be within 1 to 24 hours, based on the

SONGS plant and equipment conditions.

~~List of the critical transmission lines~~List of critical transmission lines/grid conditions:

Critical Line(s) Out In SCE Territory

Palo Verde -Devers 500 kV Line
Ellis- Johanna & Ellis-Santiago 230 kV Lines
Lugo-Serrano & Mira Loma-Serrano 500 kV Lines
Lugo- Mira Loma 2&3 500 kV Lines
Two Midway - Vincent 500 kV Lines
SONGS- Serrano & SONGS - Chino 230 kV Lines

Critical Line(s) Out in SDG&E Territory

~~Palo Verde- N. Gila 500 kV Line~~Hassayampa-N. Gila 500 kV Line
N. Gila- Imperial Valley 500 kV Line
Imperial Valley- Miguel 500 kV Line
Imperial Valley- Miguel 500 kV Line & Imperial Valley- LaRosita 230 kV Line
SONGS-San Luis Rey 230 kV Tap & SONGS - Mission 230 kV Line

~~Critical Grid Conditions:~~
~~SCE/SDG&E Tie Separation at SONGS:~~

~~SCE/SDG&E Tie Open, Unit 3 On-Line (Unit 2 Off-Line)~~
~~SCE/SDG&E Tie Open, Unit 2 On-Line (Unit 3 Off-Line)~~

Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions, such as the above cases, that could render the offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to provide electrical support to safe shutdown loads and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. The following actions are required:

a. Procedures and programs shall be in effect to ensure that the SONGS Control Room is immediately notified of such conditions.

b. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, render the offsite power supply Inoperable. The SONGS Control Room shall be immediately notified of such conditions.

c. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.

d. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to SCE.

(References 1, 2, 19, 21)

System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the ~~Western Systems Coordinating Council (WSCC) region~~Western Electricity Coordinating Council (WECC). (Reference 7)

8. In the event of loss of the SONGS offsite power supply:

Note: SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours. The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety.

a. Highest possible priority shall be given to restoring power to the SONGS switchyard. Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. (References 15, 26, 28)

b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.

c. Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.

d. Formal programs and procedures shall be in place to effect items a, b, and c above.

(References 14, 15, 16, 17, 26, 27)

9. Grid frequency shall be maintained at 60 Hertz (nominal). A trip of one SONGS unit shall not cause the grid frequency to dip below 59.7 Hertz. SCE and SDG&E comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.
~~The following operations are initiated for low system frequency conditions:~~

~~a. At 59.3 Hertz, SCE system load shedding program is initiated.~~

~~b. At 58.2 Hertz, automatic separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when either San Onofre unit is pre-selected to separate with the SDG&E system.~~

~~c. At 58.0 Hertz, manual separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when either San Onofre unit is pre-selected to separate with the SDG&E system.~~

~~d. At 57.0 Hertz, automatic separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when no San Onofre unit is selected to separate with the SDG&E system.~~

~~e. At 56.8 Hertz, manual separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when no San Onofre unit is selected to separate with the SDG&E system.~~

~~**Note: The above separation setpoints are provided for information only. SCE and SDG&E are currently reviewing the 57 Hz separation setpoint. This setpoint may be changed to**~~

~~**ensure that system separation occurs prior to a trip of the nuclear unit(s), which also occurs at approximately 57 Hz. SCE will inform the ISO of any changes to the system separation setpoint.**~~

Note: System separation between SCE and SDG&E at the SONGS bus tie on low grid frequency mentioned in the previous version of the TCA is being removed from SONGS by mid-2002. Increased load shedding schemes by SDG&E have been implemented which preclude the need for system separation at SONGS bus ties on low frequency.

(References 7, 20)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report shall be maintained. It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7)

11. Patrol and inspection of SCE and SDG&E transmission lines shall be ~~patrolled annually~~ performed in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice or as required by the NRC plant-operating license, whichever requirement is more stringent. These patrols and inspections are to ensure that the physical and electrical integrity of transmission system components ~~is~~ are maintained. (Reference~~s~~ 7~~, 22~~)

12. Line insulators~~, pole hardware terminals, and tower hardware terminals within the first three miles from the San Onofre switchyard shall be inspected annually and washed at least two times a year to reduce~~ on lines which carry power from the plant to the grid shall be washed as required by the NRC plant-operating license or on an appropriate wash cycle in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. The purpose and frequency of which is proven to prevent line outages that may result from flashovers due to ~~possible~~ accumulated contamination. (Reference~~s~~ 7~~, 22~~)

13. ~~Preventive m~~Maintenance, testing and calibration of ~~SONGS switchyard circuit breakers~~ SCE and SDG&E station equipment and protective relays shall be performed in accordance with the current ISO approved Electrical Station Maintenance Practice or as required by the NRC plant operating license, whichever requirement is more stringent. ~~as follows:~~

~~SCE: 230 kV circuit breakers are overhauled every 300 normal operations or 25 kickouts. Response time/trip testing is performed annually. Transmission line relays are tested biannually.~~ (References 7~~, 24, 25~~)

~~SDG&E: 230 kV circuit breakers are overhauled every five years. Trip testing is performed annually. Transmission line relays are tested biannually. (Reference 7)~~

14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of SONGS switchyard battery chargers and DC system components shall be performed routinely. (Reference 7, 23)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS 2 & 3 Updated Final Safety Analysis Report (UFSAR) shall be provided annually. These updates will be used by SCE to prepare a UFSAR change submittal to the NRC. SONGS is required by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.

REFERENCES

1) SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems

2) 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems

3) NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System

4) NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System

5) NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems

6) NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems

7) SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power

8) ANSI/IEEE Std. 765-1983 Preferred Power Supply for Nuclear Power Generating Stations

9) SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident

10) SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation

11) SONGS Design Calculation E4C-092, Short Circuit Studies

12) SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting

13) DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems

14) 90051, SONGS Station Blackout Analyses

15) NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors

16) Letter from M. 0. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, `Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"

17) Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"

18) System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station ~~(Rev. January, 1998)~~(Current approved revision)

19) ~~ECC Operating Procedure: Songs Voltage (Rev. 12/09/1997)~~GCC Operating Procedure: SONGS Voltage (Current approved revision)

20) System Operating Bulletin 113, San Onofre 220 kV System Separation ~~(Rev. April 15, 1995)~~(Current approved revision)

21) Regulatory Guide 1.93, Availability of Electric Power Sources

~~22) SCE Division Order 40.35, Transmission Line Routine Patrol, Inspection, Scheduling, and Record Keeping (Rev. 10/87)~~

23) SCE Division Order 60.20, Storage Batteries ~~(Rev. 3/82)~~(Current approved revision)

~~24) SCE Division Order 50.10, Predictive Maintenance Circuit Breakers and Switches (Rev. 6/96)~~

~~25) SCE Division Order 50.20, Relay and Equipment Tests (Rev. 3/94)~~

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration ~~(Rev. 12/97)~~(Current approved revision)

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV ~~(Rev. March 18, 1996)~~(Current approved revision)

28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies ~~(Rev. 12/97)~~(Current approved revision)

TRANSMISSION CONTROL AGREEMENT

APPENDIX F

NOTICES

NOTICES

California Independent System Operator

Name of Primary Representative:	Deborah A. Le Vine
Title:	Director of Contracts
Address:	151 Blue Ravine Road
City/State/Zip Code:	Folsom, California 95630
Email Address:	dlevine@caiso.com
Phone:	(916) 351-2144
Fax No:	(916) 351-2487

Name of Alternative Representative:	Randy Abernathy
Title:	Vice President of Market Services
Address:	151 Blue Ravine Road
City/State/Zip Code:	Folsom, California 95630
Email Address:	rabernathy@caiso.com
Phone:	(916) 351-4435
Fax No:	(916) 351-2350

Pacific Gas and Electric Company

Name of Primary Representative:	Rod Maslowski
Title:	Director, Electric System Operations
Address:	77 Beale Street, Room 1526
City/State/Zip Code:	San Francisco, CA 94105
Email Address:	RJM8@pge.com
Phone:	415-973-1218
Fax No:	415-973-3341

Name of Alternative Representative:	~~Robert Stuart~~Judi Mosley
Title:	~~Manager, Operations Engineering~~Director, Interconnection Services
Address:	77 Beale Street, Room ~~1514~~1355
City/State/Zip Code:	San Francisco, CA 94105
Email Address:	~~RBS2~~JKM8@PGE.COM
Phone:	415 973-~~1962~~4408
Fax No:	415 973-~~8616~~7891

San Diego Gas & Electric Company

Name of Primary Representative:	Geoff Gaebe
Title:	Director - Electrical Engineering
Address:	8316 Century Park Court
City/State/Zip Code:	San Diego, CA 92123
Email Address:	ggaebe@semprautilities.com
Phone:	858-654-1636
Fax No:	858-654-1692

Name of Alternative Representative:	Ali Yari
Title:	Manager Grid Operation Services
Address:	9060 Friars Road
City/State/Zip Code:	San Diego, CA 92108
Email Address:	yari@semprautilities.com
Phone:	619-725-8639
Fax No:	619-683-3291

Southern California Edison Company

Name of Primary Representative:	Richard M. Rosenblum
Title:	Senior Vice President, Transmission & Distribution
Address:	2244 Walnut Grove Ave., GO4
City/State/Zip Code:	Rosemead, California 91770
Email Address:	Richard.Rosenblum@SCE.com
Phone:	(626) 302-2123
Fax No:	(626) 302-2781

Name of Alternative Representative:	John R. Fielder
Title:	Senior Vice President, Regulatory Policy & Affairs
Address:	2244 Walnut Grove Ave., GO4
City/State/Zip Code:	Rosemead, California 91770
Email Address:	John.Fielder@SCE.com
Phone:	(626) 302-3440
Fax No:	(626) 302-2970

City of Vernon

Name of Primary Representative:	Bruce V. Malkenhorst
Title:	City Administrator
Address:	4305 Santa Fe Avenue
City/State/Zip Code:	Vernon, California 90058
Email Address:	bmalkenhorst@ci.vernon.ca.us
Phone:	(323) 583-8811 extension 266
Fax No:	(323) 581-7924

Name of Alternative Representative:	Kenneth J. DeDario
Title:	Director of Utilities
Address:	4305 Santa Fe Avenue
City/State/Zip Code:	Vernon, California 90058
Email Address:	kdedario@ci.vernon.ca.us
Phone:	(323) 583-8811 extension 211
Fax No:	(323) 826-1425

City of Anaheim

Name of Primary Representative:	Sheryll A. Schroeder
Title:	City Clerk
Address:	200 S. Anaheim Blvd.
City/State/Zip Code:	Anaheim, California 92805
Email Address:	sschroeder@anaheim.net
Phone:	(714) 765-5645
Fax No:	(714) 765-4105

Name of Alternative Representative:	Marcie L. Edwards
Title:	Public Utilities General Manager
Address:	201 S. Anaheim Blvd., Suite 1101
City/State/Zip Code:	Anaheim, California 92805
Email Address:	medwards@anaheim.net
Phone:	(714) 765-5173
Fax No:	(714) 765-4138

City of Azusa

Name of Primary Representative:	Joseph Hsu
Title:	Director of Utilities
Address:	729 N. Azusa Avenue
City/State/Zip Code:	Azusa, CA 91702
Email Address:	jhsu@ci.azusa.ca.us
Phone:	(626) 812-5171
Fax No:	(626) 334-3163

Name of Alternative Representative:	Bob Tang
Title:	Assistant Director of Resource Management
Address:	729 N. Azusa Avenue
City/State/Zip Code:	Azusa, CA 91702
Email Address:	btang@ci.azusa.ca.us
Phone:	(626) 812-5214
Fax No:	(626) 334-3163

City of Banning

Name of Primary Representative:	Paul Toor
Title:	Public Works Director
Address:	99 East Ramsey Street
City/State/Zip Code:	Banning, California 92220
Email Address:	ptoor@ci.banning.ca.us
Phone:	(909) 922-3130
Fax No:	(909) 922-3141

Name of Alternative Representative:	Fred Mason
Title:	Power Resource Specialist
Address:	176 East Lincoln Street
City/State/Zip Code:	Banning, California 92220
Email Address:	fmason@ci.banning.ca.us
Phone:	(909) 922-3265
Fax No:	(909) 849-1550

City of Riverside

Name of Primary Representative:	Thomas P. Evans
Title:	Public Utilities Director
Address:	3900 Main Street
City/State/Zip Code:	Riverside, CA 92522
Email Address:	tevans@ci.riverside.ca.us
Phone:	(909) 826-5502
Fax No:	(909) 369-0548

Name of Alternative Representative:	Gary L. Nolff
Title:	Power Contracts/Projects Manager
Address:	2911 Adams Street
City/State/Zip Code:	Riverside, CA 92504
Email Address:	gnolff@pac.state.ca.us
Phone:	(909) 351-6313
Fax No:	(909) 351-6328

ATTACHMENT C

CERTIFICATE OF CONCURRENCE
(Pursuant to 18 C.F.R. §§ 35.1(a) and 131.52)

This is to certify that Pacific Gas and Electric Company assents to and concurs in the rate schedule supplement described below, which the California Independent System Operator Corporation ("ISO") has filed, and hereby files this certificate of concurrence in lieu of the filing of the rate schedule supplement specified.

The rate schedule supplement is several amendments to the Transmission Control Agreement among the ISO and Participating Transmission Owners, ISO Rate Schedule FERC No. 7, filed November 25, 2002.

PACIFIC GAS AND ELECTRIC COMPANY

By Stuart K. Gardiner

Stuart K. Gardiner
Attorney at Law
Law Department, B30A
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, California 94120

Dated: November 22, 2002

CERTIFICATE OF CONCURRENCE
(Pursuant to 18 C.F.R. §§ 35.1(a) and 131.52)

This is to certify that San Diego Gas & Electric Company assents to and concurs in the rate schedule supplement described below, which the California Independent System Operator Corporation ("ISO") has filed, and hereby files this certificate of concurrence in lieu of the filing of the rate schedule supplement specified.

The rate schedule supplement is several amendments to the Transmission Control Agreement among the ISO and Participating Transmission Owners, ISO Rate Schedule FERC No. 7, filed November 25, 2002.

SAN DIEGO GAS & ELECTRIC COMPANY

By James P. Avery

James P. Avery
Senior Vice President
8330 Century Park Court
San Diego, CA 92123

Dated: November 22, 2002

CERTIFICATE OF CONCERRENCE
(Pursuant to 18 C.F.R. §§ 35.1(a) and 131.52)

This is to certify that Southern California Edison Company assents to and concurs in the rate schedule supplement described below, which the California Independent System Operator Corporation ("ISO") has filed, and hereby files this certificate of concurrence in lieu of the filing of the rate schedule supplement specified.

The rate schedule supplement is several amendments to the Transmission Control Agreement among the ISO and Participating Transmission Owners, ISO Rate Schedule FERC No. 7, filed November 25, 2002.

Southern California Edison Company

By Anna J. Valdberg

Anna J. Valdberg
Attorney at Law
SOUTHERN CALIFORNIA EDISON COMPANY
P.O. Box 800
2244 Walnut Grove Avenue
Rosemead, California 91770
(626) 302-1058
anna.valdberg@SCE.com

Dated: November 22, 2002

ATTACHMENT D

NOTICE SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER03-_____ -000**

Notice of Filing
[ ]

Take notice that the California Independent System Operator Corporation ("ISO"), on November 25, 2002, tendered for filing revisions to the Transmission Control Agreement ("TCA") for acceptance by the Commission. The ISO states that the purpose of the amendment is (1) to clarify, amend, and supplement various provisions of the current TCA in response to issues raised by the Cities of Anaheim, Azusa, Banning, and Riverside, California (together "Southern Cities"), which have applied to become Participating Transmission Owners; (2) to identify the transmission interests that Southern Cities will be turning over to the ISO's Operational Control, and (3) to make certain other changes to the TCA proposed by the ISO and the current Participating Transmission Owners.

The ISO states that this filing has been served on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties, including the signatories to the TCA, with effective Scheduling Coordinator Agreements under the ISO Tariff.

The ISO is requesting waiver of the 60-day notice requirement to allow the TCA to be made effective January 1, 2003.

Any person desiring to be heard or to protest the filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). All such motions or protests must be filed in accordance with § 35.9 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference

Room. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).