California Independent
System Operator Corporation

December 3, 2010

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **California Independent System Operator Corporation**
Docket No. ER06-1360-_____
Docket No. ER11-_____-000

Filing of Updated Transmission Control Agreement in eTariff Format and Request for Waiver of Notice Requirement

Dear Secretary Bose:

The California Independent System Operator Corporation submits for Commission acceptance the Third Replacement Transmission Control Agreement (TCA) for filing in eTariff format.[1] The ISO submits this filing as a follow-up to the notice it filed on November 23, 2010 in Docket No. ER06-1360-000 that it assumed operational control of the transmission rights of Trans Bay Cable, LLC as of 13:00 Pacific Standard Time on November 23, 2010 and that the pages of the TCA establishing Trans Bay Cable as a new participating transmission owner became effective as of that date. The ISO requests a waiver of the 60-day prior notice requirement to allow the entire eTariff version of the TCA to be made effective as of 13:00 PST on November 23, 2010.

I. The ISO's November 23 Notice in Docket No. ER06-1360

In the Commission's October 10, 2006 order in Docket No. ER06-1360, the Commission accepted for filing the revisions to the TCA to identify the transmission rights that Trans Bay Cable proposed to turn over to the ISO's

[1] The ISO submits this filing in compliance with Order No. 714, *Electronic Tariff Filings*, FERC Stats. & Regs. ¶ 31,276 (2009). The ISO is also sometimes referred to as the CAISO. The TCA is presently identified as ISO FERC Electric Tariff No. 7, Second Replacement Transmission Control Agreement. The ISO is submitting this filing using the ISO's eTariff Tariff Identifier associated with ISO rate schedules, as this is a multi-party agreement that the ISO believes is more appropriately treated as a rate schedule than a tariff. However, if the Commission directs the ISO to continue and identify the TCA as an electric tariff, the ISO requests the Commission authorize the use of a new eTariff Tariff Identifier specifically associated with the TCA to avoid the confusion that might be created by integrating the TCA with the current ISO tariff.

operational control and directed the ISO to submit revised pages of the TCA to establish Trans Bay Cable as a new participating transmission owner signatory to the TCA and implement related revisions upon providing notification of the effective date of these TCA pages.[2] In the ISO's November 23 filing, the ISO advised the Commission that it was unable at that time to submit the revised pages of the TCA applicable to Trans Bay Cable in compliance with that order simultaneous with its notice of the effective date of these TCA pages.

As a result of the Commission's intervening implementation of its new eTariff software system, the ISO needed to import the entire TCA into that eTariff software in conjunction with the submittal of the three affected TCA pages, as this is the first time that the TCA has been revised since the implementation of eTariff. Due to the complications of having to make the conversion of the TCA into eTariff format, the ongoing strain on the ISO's resources of having to prepare filings of numerous Large Generator Interconnection Agreements subject to severe time constraints, and the limited availability of ISO personnel due to the Thanksgiving holiday week, the ISO was unable to undertake the effort to convert the TCA into eTariff format in order to submit the revised TCA into eTariff simultaneous with the filing of the November 23 notice of assumption of operational control of Trans Bay Cable's transmission rights. Since November 23, the ISO has completed the import of the TCA into the eTariff software.

Consequently, the ISO is now submitting the TCA signature page for Trans Bay Cable and associated pages of TCA Appendices A and F (previously identified as Original Sheet Nos. 72D, 103D, and 238) with a request for an updated effective date as directed in the Commission's October 10, 2006 order in Docket No. ER06-1360, together with the rest of the TCA in eTariff format. The ISO requests that these TCA pages applicable to Trans Bay Cable – as well as the rest of the eTariff version of the TCA – become effective as of 13:00 PST on November 23, 2010.

II. Request for Waiver of Notice Requirement

To accommodate the foregoing requested effective date, the ISO respectfully requests waiver, pursuant to Section 35.11 of the Commission's regulations (18 C.F.R. § 35.11), of the 60-day notice requirement contained in Section 35.3 of the Commission's regulations (18 C.F.R. § 35.3), in order to permit the TCA to become effective as of 13:00 PST on November 23, 2010. Granting the waiver will be consistent with the notice filed by the ISO on November 23, 2010 in Docket No. ER06-1360 and with the directive of the

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[2] *California Independent System Operator Corporation*, 117 FERC ¶ 61,029 (2006), p. 7 (ordering paragraph (B)). The Commission clarified the effective date of revisions to other provisions of the TCA in subsequent orders issued in Dockets No. ER06-1360-001 (*California Independent System Operator Corporation*, 117 FERC ¶ 61,181 (2006)) and ER06-1360-002 (letter order issued April 9, 2007).

Commission's October 10, 2006 order in that docket. No harm will result to any entity from the effective date for the TCA, and the agreement does not result in any increase in rates or charges. Granting the requested waiver, therefore, is appropriate.

III. Contents of Filing

Enclosed for filing are each of the following:

(1) this transmittal letter; and

(2) the eTariff version of the TCA.

IV. Correspondence

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

Michael D. Dozier*
Senior Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7048
Fax: (916) 608-7222
E-mail: mdozier@caiso.com

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

V. Service

The ISO has served copies of this notice on the California Public Utilities Commission, the California Energy Commission, its participating transmission owners, and the parties to Docket No. ER06-1360. In addition, the ISO is posting this notice on the ISO's website.

VI. Conclusion

The ISO respectfully requests that the Commission accept the Transmission Control Agreement, including the page of the TCA establishing Trans Bay Cable as a new participating transmission owner, in eTariff format effective as of 13:00 PST on November 23, 2010. If there are any questions concerning this notice, please contact the undersigned.

Respectfully submitted,

By: *<u>/s/ Michael D. Dozier</u>*
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Attorneys for the California Independent System Operator Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 3rd day of December, 2010, at Folsom, California.

Anna Pascuzzo

Anna Pascuzzo

TRANSMISSION CONTROL AGREEMENT

Among
The Independent System Operator
and
Transmission Owners

Tariff Record Proposed Effective Date: 11/23/10
Version Number: 0.0.0
Option Code: A

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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.

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. In addition, Western Area Power Administration ("Western") may be required to withdraw as a Participating TO pursuant to Section 26.14.1.

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 of any affected transmission lines, associated facilities, or Entitlements in accordance with this Section 3.4, the ISO promptly shall prepare the necessary changes to this Agreement and to the ISO Tariff (if any), make a filing with FERC pursuant to Section 205 of the FPA, and take whatever other 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, except that Western shall only be required to place under the ISO's Operational Control the transmission lines and associated facilities that it owns or to which it has Entitlements as set forth in Appendix A (Western). 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 information for a given Participating TO available to that same Participating TO

on WEnet or a secure ISO-maintained internet website. The ISO will provide a copy of the ISO Register information to other entities that can demonstrate a legitimate need for the information in accordance with screening procedures posted on the ISO Home Page and filed with FERC.

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.

4.4.4 **Trans Bay Cable**

4.4.4.1 In addition to the foregoing, the ISO, Trans Bay Cable LLC ("Trans Bay Cable"), and the Participating TOs acknowledge and agree that, following the ISO's approval of Trans Bay Cable's application for Participating TO status and upon the effective date of Trans Bay Cable's TO Tariff as approved by FERC, Trans Bay Cable shall be entitled and obligated to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the

network in which it has Entitlements through Trans Bay Cable's Transmission Revenue Requirement as established from time to time by FERC, including the specific rate principles approved by FERC in Docket No. ER05-985, to the extent that the transmission assets and associated facilities used to provide the Entitlements, as well as the Entitlements themselves, are placed under ISO Operational Control.

4.4.4.2 In reliance on the continued availability of a FERC-approved Transmission Revenue Requirement, as set forth above, Trans Bay Cable will not withdraw from this Agreement except in connection with the transfer, sale or disposition of any of its Entitlements in compliance with Sections 3.3, 4.4, and any other applicable provision of this Agreement.

4.4.4.3 If Trans Bay Cable should seek to transfer, sell or dispose of its Entitlements or any part thereof, then in addition to any and all other obligations imposed on such a transfer, sale or disposition by this Agreement, any applicable provisions of the ISO Tariff, and FERC rules and regulations, Trans Bay Cable shall require as a condition of such transfer, sale or disposition that the transferee of any of its Entitlement(s): (a) assume in writing Trans Bay Cable's rights and obligations under this Agreement, including without limitation all of the obligations imposed by this Section 4.4.4, *e.g.*, the obligation to recover the just and reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has Entitlements, as set forth in Section 4.4.4.1, exclusively through a FERC-approved Transmission Revenue Requirement; (b) become a

Participating TO in the ISO; and (c) assume the obligation to bind each and every one of its transferees, successors and assigns to all of the obligations assumed by Trans Bay Cable under this Agreement. For the avoidance of doubt, the transfer of any of Trans Bay Cable Entitlements cannot take place unless and until the holder of any such Entitlements has, in conjunction with the transfer, become a Participating TO in the ISO.

4.4.4.4 For the avoidance of doubt, the Parties hereby also confirm that the Operating Memorandum dated May 16, 2005, between Trans Bay Cable, the City of Pittsburg, California, and Pittsburg Power Company and filed by Trans Bay Cable in Docket No. ER05-985, including the option agreement contained therein, does not address or pertain to any transfer, disposition, sale or purchase of any of Trans Bay Cable's Entitlements.

4.4.4.5 Nothing in this Section 4.4.4 shall be interpreted as affecting the right of any party to seek to increase or decrease, at the FERC or appeals therefrom, the established or proposed Transmission Revenue Requirement of Trans Bay Cable or any subsequent holder of any of the Entitlements.

4.4.4.6 Notwithstanding the foregoing subsections of Section 4.4.4, this Section 4.4.4 shall become null and void in the event of and upon the first to occur of: (a) Trans Bay Cable receives for three (3) consecutive months either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff, or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff, with each such underpayment or pro rata reduction equal to or greater than twenty percent

(20%) of the monthly amount due and owing to Trans Bay Cable from the ISO, or (b) Trans Bay Cable receives either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff which, when calculated on a cumulative annual basis, is equal to or greater than five percent (5%) of the total amount due and owing to Trans Bay Cable from the ISO for the twelve (12) month period ending prior to the month or months in which such underpayment or pro rata reduction occurs, *provided* such an underpayment or pro rata reduction does not result from: (i) Access Charge sales fluctuations that impact the monthly Access Charge revenue disbursement to Trans Bay Cable, but which are subject to annual TRBAA true-ups to be made by the Participating TO pursuant to Section 6.1 of Schedule 3 of Appendix F of the ISO Tariff; (ii) Trans Bay Cable's action or failure to act; (iii) an error that has been corrected by the ISO; or (iv) a billing or payment dispute between Trans Bay Cable and the ISO.

4.4.4.7 Should this Section 4.4.4 become null and void under Section 4.4.4.6, then Trans Bay Cable, the ISO and the other Participating TOs shall remain bound by all of the remaining provisions of this Agreement.

4.4.5 **Startrans IO**

4.4.5.1 In addition to the foregoing, the ISO, Startrans IO, L.L.C. ("Startrans IO"), and the Participating TOs acknowledge and agree that, following the ISO's approval of Startrans IO's application for Participating TO status and upon the effective date of Startrans IO's TO Tariff as approved by FERC, Startrans IO shall be entitled and obligated to recover the just and

reasonable costs of developing, financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has transmission rights and Entitlements through Startrans IO's Transmission Revenue Requirement as established from time to time by FERC, including the specific rate principles approved by FERC in Docket No. ER08-413, to the extent that the transmission assets and associated facilities used to provide the transmission rights and Entitlements, as well as the transmission rights and Entitlements themselves, are placed under ISO Operational Control.

4.4.5.2 In reliance on the continued availability of a FERC-approved Transmission Revenue Requirement, as set forth above, Startrans IO will not withdraw from this Agreement except in connection with the transfer, sale or disposition of any of its transmission rights and Entitlements in compliance with Sections 3.3, 4.4, and any other applicable provision of this Agreement.

4.4.5.3 If Startrans IO should seek to transfer, sell or dispose of its transmission rights and Entitlements or any part thereof, then in addition to any and all other obligations imposed on such a transfer, sale or disposition by this Agreement, any applicable provisions of the ISO Tariff, and FERC rules and regulations, Startrans IO shall require as a condition of such transfer, sale or disposition that the transferee of any of its transmission rights and Entitlement(s): (a) assume in writing Startrans IO's rights and obligations under this Agreement, including without limitation all of the obligations imposed by this Section 4.4.5, *e.g.*, the obligation to recover the just and reasonable costs of developing,

financing, constructing, operating and maintaining transmission assets and associated facilities forming part of the network in which it has transmission rights and Entitlements, as set forth in Section 4.4.5.1, exclusively through a FERC-approved Transmission Revenue Requirement; (b) become a Participating TO in the ISO; and (c) assume the obligation to bind each and every one of its transferees, successors and assigns to all of the obligations assumed by Startrans IO under this Agreement. For the avoidance of doubt, the transfer of any of Startrans IO's transmission rights and Entitlements cannot take place unless and until the holder of any such transmission rights and Entitlements has, in conjunction with the transfer, become a Participating TO in the ISO.

4.4.5.4 Nothing in this Section 4.4.5 shall be interpreted as affecting the right of any party to seek to increase or decrease, at the FERC or appeals therefrom, the established or proposed Transmission Revenue Requirement of Startrans IO or any subsequent holder of any of the transmission rights and Entitlements.

4.4.5.5 Notwithstanding the foregoing subsections of Section 4.4.5, this Section 4.4.5 shall become null and void in the event of and upon the first to occur of: (a) Startrans IO receives for three (3) consecutive months either an underpayment, pursuant to Section 11.18.3 of the ISO Tariff, or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff, with each such underpayment or pro rata reduction equal to or greater than twenty percent (20%) of the monthly amount due and owing to Startrans IO from the ISO, or (b) Startrans IO receives either an underpayment, pursuant to Section 11.18.3 of the

ISO Tariff or a pro rata reduction in payments under Section 11.16.1 of the ISO Tariff which, when calculated on a cumulative annual basis, is equal to or greater than five percent (5%) of the total amount due and owing to Startrans IO from the ISO for the twelve (12) month period ending prior to the month or months in which such underpayment or pro rata reduction occurs, *provided* such an underpayment or pro rata reduction does not result from: (i) Access Charge sales fluctuations that impact the monthly Access Charge revenue disbursement to Startrans IO, but which are subject to annual TRBA adjustment true-ups to be made by the Participating TO pursuant to Section 6.1 of Schedule 3 of Appendix F of the ISO Tariff; (ii) Startrans IO's action or failure to act; (iii) an error that has been corrected by the ISO; or (iv) a billing or payment dispute between Startrans IO and the ISO.

4.4.5.6 Should this Section 4.4.5 become null and void under Section 4.4.5.5, then Startrans IO, the ISO and the other Participating TOs shall remain bound by all of the remaining provisions of this Agreement.

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. CRITICAL PROTECTIVE SYSTEMS THAT SUPPORT ISO CONTROLLED GRID OPERATIONS

8.1. Remedial Action Systems, Under Frequency Load Shedding, Under Voltage Load Shedding.

Each Participating TO shall coordinate its Critical Protective Systems with

the ISO, other Transmission Owners, and Generators to ensure that its Remedial Action Schemes ("RAS"), Under Frequency Load Shedding ("UFLS"), and Under Voltage Load Shedding ("UVLS") schemes function on a coordinated and complementary basis in accordance with WSCC/NERC planning, reliability, and protection policies and standards. Participating TOs that are parties to contracts affecting RAS, UFLS, and UVLS schemes shall make reasonable efforts to amend those contracts in order to permit the RAS, UFLS, and UVLS schemes to be operated in accordance with WSCC/NERC planning, reliability, and protection policies and standards and the ISO Tariff.

Each Participating TO, in conjunction with the ISO, shall identify, describe, and provide to the ISO the functionality of all RAS for electric systems operating at 200 kV nominal voltage or higher and any other lower voltage lines that the ISO and Participating TO determine to be critical to the reliability of the ISO Controlled Grid. Each Participating TO shall provide to the ISO a description of the functionality of UFLS and UVLS schemes that protect the security and reliability of transmission facilities on the ISO Controlled Grid.

Each Participating TO shall maintain the design, functionality, and settings of its existing RAS, UFLS, and UVLS schemes. New or existing schemes that are functionally modified must be in accordance with WSCC/NERC planning, reliability, and protection policies and standards. Each Participating TO shall notify the ISO in advance of all RAS, UFLS, and UVLS schemes functionality and setting changes that affect transmission facilities on the ISO Controlled Grid. Each Participating TO shall not disable or take clearances on RAS or UVLS

schemes without the approval of the ISO through the Maintenance Outage and Forced Outage coordination process in accordance with the ISO Tariff. Clearances on UFLS may be taken without approval depending upon the armed load disabled as agreed to between the Participating TO and ISO and incorporated in the Operating Procedures.

The requirements of this Section 8.1 shall apply only to the transmission facilities that are part of the ISO Controlled Grid.

8.2. Protective Relay Systems.

Each Participating TO shall provide to the ISO protective relay system functional information necessary to perform system planning and operating analysis, and to operate transmission facilities on the ISO Controlled Grid in compliance with WSCC/NERC planning, reliability and protection policies and standards.

The requirements of this Section 8.2 shall apply only to the transmission facilities that are part of the ISO Controlled Grid.

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.

10.5 Interconnection Responsibilities of Western.

Notwithstanding any other provision of this Section 10, the responsibilities of Western to allow interconnection to its Path 15 Upgrade facilities and Entitlements set forth in Appendix A (Western) shall be as set forth in Western's General Requirements for Interconnection as those requirements are set forth in Western's TO Tariff or in Western's "Open Access Transmission Tariff" ("OATT"), as applicable. Western shall be subject to the provisions of this Section 10 to the extent they are not inconsistent with the provisions of Western's TO Tariff or OATT, as applicable. Execution of this Agreement shall not constitute agreement of any Party that Western is in compliance with FERC's regulations governing interconnections.

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 has adopted and shall maintain, in consultation with the Participating TOs through the Transmission Maintenance Coordination Committee, and in accordance with the requirements of this Agreement, the standards for the maintenance, inspection, repair, and replacement of transmission facilities under its Operational Control in accordance with Appendix C. These standards, as set forth in Appendix C, are and shall be performance-based or prescriptive or both, and 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. Availability.

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

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

14.2.3 **Availability Measure Target**. The ISO and each Participating TO shall jointly develop for the Participating TOs an availability measure target, which may be defined by a range. The target will be based on

prior Participating TO performance and developed in accordance with Appendix C of this Agreement.

14.2.4 **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 be determined in accordance with Appendix C of this Agreement.

14.2.5 **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.

14.2.6 **Public Record**. The Participating TO's annual availability measure calculation with its summary data shall be made available to the public.

14.3. Revisions.

The ISO and Participating TOs shall periodically review Appendix C, through the Transmission Maintenance Coordination Committee process, and in accordance with the provisions of Appendix C and this Agreement shall modify Appendix C as necessary.

14.4. Incentives and Penalties.

The ISO may, subject to regulatory approval, and as set forth in Appendix C, develop 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 to 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 Maintenance Standards**. Each Participating TO shall provide to the ISO, as set forth in Appendix C hereto: (1) the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control; and (2) information, notices, or reports regarding the Participating TO's compliance with the inspection, maintenance, repair, and replacement standards set forth in Appendix C hereto.

17.2.2 **Other Records**. Each Participating TO shall provide to the ISO and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control, 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; and

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

17.2.4 **Other Reports**. The ISO may, in accordance with the provisions of this Agreement and Appendices hereto, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports as are necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO in the manner and time prescribed by this Agreement or Appendices hereto or, if no specific requirements are so prescribed, 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 periodically review the requirements of this Section 17 and shall, consistent with reliability and regulatory needs, other provisions of this Agreement, and Appendices hereto, 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, materials, data, or information ("Data") provided to it by any other Party that reflects or contains: (a) Data treated as confidential or commercially sensitive under the confidentiality provisions of Section 20.3 of the ISO Tariff; (b) critical energy infrastructure information, as defined in Section 388.113(c)(1) of the FERC's regulations (c) technical information and materials that constitute valuable, confidential, and proprietary information, know-how, and trade secrets belonging to a Party, including, but not limited to, information relating to drawings, maps, reports, specifications and records and/or software, data, computer models, and related documentation; or (d) Data that was previously public information but that was removed from public access in accordance with FERC's policy statement issued on October 11, 2001 in Docket No. PL02-1-000 in response to the September 11, 2001 terrorist attacks. In order to be subject to the confidentiality protections of this Section 26.3, Data provided by a Party to the ISO after January 1, 2005 which is to be accorded confidential treatment, as set forth above, shall be marked as "Confidential Data." Such a marking requirement, however, shall not be applicable to the Data provided by a Party to the ISO prior to January 1, 2005 so long as the Data qualifies for confidential treatment hereunder. Notwithstanding the foregoing, 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.

26.14 Consistency with Federal Laws and Regulations

26.14.1 **No Violation of Law**. Nothing in this Agreement shall compel any Party to: (1) violate any federal statute or regulation; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statute, or regulation or order lawfully promulgated thereunder. No Party shall incur any liability by failing to comply with a provision of this Agreement that is inapplicable to it by reason of being inconsistent with any

federal statute, or regulation or order lawfully promulgated thereunder; provided, however, that such Party shall use its best efforts to comply with this Agreement to the extent that applicable federal laws, and regulations and orders lawfully promulgated thereunder, permit it to do so.

If Western issues or revises any federal regulation or order with the intent or effect of limiting, impairing, or excusing any obligation of Western under this Agreement, then unless Western's action was expressly directed by Congress, any Party, by giving thirty days' advance written notice to the other Parties, may require Western to withdraw from this Agreement, notwithstanding any other notice period in Section 3.3.1. If such notice is given, the ISO and Western promptly shall meet to develop arrangements needed to comply with Western's obligation under Section 3.3.3 concerning non-impairment of ISO Operational Control responsibilities.

26.14.2 **Federal Entity Indemnity**. No provision of this Agreement shall require any Participating TO to give an indemnity to Western or for Western to give an indemnity to any Participating TO. If any provision of this Agreement requiring Western to give an indemnity to the ISO or the ISO to impose a sanction on Western is unenforceable against a federal entity, the affected Party shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any

provisions of this Agreement that are not enforceable against the federal entity.

26.14.3 **Recovery for Unenforceable Indemnity**. To the extent that a Party suffers any loss as a result of being unable to enforce any indemnity as a result of such enforcement being in violation of Section 26.14.2, it shall be entitled to seek recovery of such loss through its TO Tariff or through the ISO Tariff, as applicable.

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 _____, 2008 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:_____
Jim Detmers
Vice President, Operations

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 7th day of August, 2006 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: _____
Stewart M. Ramsay
Vice President, Asset Management & Electric Transmission

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 _____, 2006 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 24th day of July, 2006 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: _____
Ronald L. Litzinger
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 8th day of August, 2006 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, JR.
Acting City Clerk

APPROVED AS TO FORM:

_____
Jeff Harrison, Chief Assistant 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 _____, 2006 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 _____, 2006 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:_____
Diane Chagnon
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 _____, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Banning)
Appendix C
Appendix D
Appendix F

CITY OF BANNING

By:_____
Randy Anstine
City Manager

ATTEST:

_____
Marie Calderon, City Clerk

APPROVED AS TO FORM:

_____
Julie Hayward Biggs, City Attorney

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 _____, 2006 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:_____
Bradley J. Hudson, City Manager

ATTEST:

_____
City Clerk

APPROVED AS TO FORM:

_____
Supervising Deputy City Attorney

36. SIGNATURE PAGE

TRANS-ELECT NTD PATH 15, LLC

TRANS-ELECT NTD PATH 15, LLC has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 28th day of July, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Trans-Elect)
Appendix C
Appendix D
Appendix F

Trans-Elect NTD Path 15, LLC
1850 Centennial Park Drive
Suite 480
Reston, VA 20191

By: _____
Robert D. Dickerson
Executive Vice President

37. SIGNATURE PAGE

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____ day of _____, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Western)
Appendix C
Appendix D
Appendix F

Western Area Power Administration, Sierra Nevada Region
Sierra Nevada Region
114 Parkshore Drive
Folsom, CA 95630-4710

By: _____
James D. Keselburg
Regional Manager

38. SIGNATURE PAGE

CITY OF PASADENA

CITY OF PASADENA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this ____ day of _____, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Pasadena)
Appendix B (Pasadena)
Appendix C
Appendix D
Appendix F

City of Pasadena Water and Power Department
150 S. Los Robles, Suite 200
Pasadena, CA 91101

By: _____
Cynthia J. Kurtz
City Manager

39. SIGNATURE PAGE

TRANS BAY CABLE LLC

TRANS BAY CABLE LLC has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 2nd day of August, 2006 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Trans Bay Cable LLC)
Appendix C
Appendix D
Appendix F

Trans Bay Cable LLC
c/o Babcock & Brown LP
2 Harrison Street, 6th Floor
San Francisco, CA 94105
Tel: (415) 512-1515
Fax: (415) 267-1500

By: _____
David Parquet
Vice President
Trans Bay Cable LLC

40. SIGNATURE PAGE

STARTRANS IO, L.L.C.

STARTRANS IO, L.L.C. ("Startrans IO") has caused this Transmission Control Agreement to be executed by its duly authorized representative on this _____ day of _____, 2008 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Startrans IO)

Appendix C

Appendix D

Appendix F

STARTRANS IO, L.L.C.

By:_____
Madison Grose
Vice Chairman and Senior
Managing Director

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	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission	8/1/2007	Both entitlement and encumbrance.
3.	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 classified as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
4.	TANC and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. 229	Transmission system coordination, curtailment sharing, rights allocation, scheduling	1/1/2043, or on two years' notice, or earlier if other agreements terminate	Both entitlement and encumbrance
5.	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.
6.	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.
.	City-Edison Pacific Intertie D-C Transmission Facilities Agreement	LADWP	48	3/31/2041 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).
.	PP&L Agreement	PP&L, PG&E, SDG&E		2008	• California Companies are 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. Per CCPIA Edison is entitled to 43% of the capacity available on the Pacific Intertie.
.	Los Angeles-Edison Exchange Agreement	LADWP	19	May 31, 2025	• 500 MW of bi-directional firm entitlement on the PDCI transmission line.
.	Owners Coordinated Operations Agreement	PG&E, SCE, SDG&E, WAPA & COTP		SCE's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	• Provides for the continued coordinated operation of the PACI and COTP. The allocation of Available Scheduling Capability between the parties is calculated 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
6.	Pasadena-Edison 230-KV Interconnection and Transmission Agreement	Pasadena	55	8/4/2010	• 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.
7.	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
8.	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.
9.	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.
10.	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.
11.	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.
12.	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. Should LADWP change rates, SCE has the right to terminate with 60 days written 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
13.	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 for Alternate Resources.	• Edison's interconnection with IID at Mirage and the point of interconnection on the Devers – Coachella Valley line.
14.	IID Edison Transmission Service Agreement for Alternative Resources	IID		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
15.	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.
16.	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
17.	Navajo Interconnection Principles	USA, APS, SRP, NPC, LADWP, TGE	76	None	• Generation principles for emergency service.
18	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.
19.	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
20.	Mutual Assistance Transmission Agreement	IID, APS, SDG&E	74	In 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.
21.	Midway Interconnection	PG&E	09	July, 31, 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
22.	Amended and Restated Eldorado System Conveyance and Co-Tenancy	NPC, SRP, LADWP	24	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
23.	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 168 MW through WAPA's Blythe Substation, via the Eagle Mountain-Blythe 161 kV transmission line (Note: FP&L entitled to 96 MW of FTRs due to participation in facility upgrade project).
24.	SONGS Ownership and Operating Agreements	SDG&E, Anaheim, Riverside	321	In effect until termination of easement for plant site.	• 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
25.	District-Edison 1987 Service and Interchange Agreement	MWD	443	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.
26.	Edison-Arizona Transmission Agreement	APS	282	2/28/2017 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
27.	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.
28.	Power Purchase Contract Between SCE and Midway-Sunset Cogeneration Company.	Midway-Sunset Cogeneration Company.		5/8/09	• 200 MW of capacity through Midway Substation.
29.	Agreement for Mitigation of Major Loop Flow	Pacificorp, PG&E, SCE	Pacificorp R/S # 298	2/12/2020	• Pacificorp to operate Phase Shifting Transformers on the Sigurd-Glen Canyon and Pinto-Four Corners Transmission Lines in accord with contract.

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[14] being placed under the California Independent System Operator's (ISO) Operational Control will meet the Applicable Reliability Criteria in 1998,[25] 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.
	Owners Coordinated Operations Agreement	PG&E, Edison, and COTP participants		SDG&E's participation terminates on 7/31/07 with CCPIA termination unless as otherwise contemplated by Section 6.3.1 of the Agreement.	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 (3 Lines) - Talega (2 lines)

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 – 76.22%; IID – 12.78%.

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[6] of San Diego Gas & Electric Company (SDG&E) is placing under the California Independent System Operator's Operational Control meets the Applicable Reliability Criteria,[7] 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;[8] (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.[9]

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.

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

[7] 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.

[8] 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.

[9] 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

[NOT USED]

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	72	(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	72	(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	54	(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)

(9) 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 (N-S) 247 MW (S-N)
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	381 MW
	IPP-Gonder Substation	"	"	"		"	54 MW
8	Nevada-Oregon Border-Sylmar	Anaheim-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	24 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.

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) a) Westwing-Mead b) Mead Substation c) Mead-Marketplace	SCPPA, MSR, Vernon, SRP, APS	 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.	 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: 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

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.

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

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
TRANSMISSION 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	N-S 195 MW S-N 142 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	220 MW
	IPP-Gonder Substation	Riverside-LADWP	Bi-directional	Northern Transmission System Agreement		See Note 4	31 MW
9.	Nevada-Oregon Border-Sylmar	Riverside-Burbank & Pasadena	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		30-Sep-09	23 MW
10.	San Onofre-Vista	Riverside-SCE	To Vista	San Onofre Nuclear Generating Station Firm Transmission Service Agmt.		See Note 5	42 MW
11.	Mead 230 kV-Vista	Riverside-SCE	To Vista	Hoover Firm Transmission Service Agreement		See Note 6	30 MW
12.	Lugo/Victorville-Vista	Riverside-SCE	To Vista	Intermountain Power Project Firm Transmission Service Agreement		See Note 7	156 MW
13.	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.

Appendix A
Trans-Elect NTD Path 15, LLC
Transmission Entitlements

Path 15 Project Facilities

Trans-Elect NTD Path 15, LLC is a participant in the Path 15 Upgrade Project, which will consist of a new, single, 83-mile, 500-kilovolt (kV) transmission line and associated substation facilities extending between the PG&E Los Banos Substation in the California Central Valley (the northern terminus of the Project) and the Gates Substation (the southern terminus of the Project), including modifications at the substations to connect the line as well as reconfigurations to the Gates – Midway 230-kV line and the 115 kV line north of Midway. Voltage support facilities will also be added at the Los Banos and Gates Substations as part of the Project. Trans-Elect NTD Path 15, LLC will own Entitlements to certain capacity on the Path 15 Project Facilities.

Trans-Elect will provide the funding for the development of the Transmission Line and Land acquisition for the Path 15 Upgrade Project (Project), as well as funding for the ongoing operation and maintenance of the transmission line and will, as a result, be granted Entitlements to capacity on the Path 15 Upgrade Project.

Under the terms of the Letter Agreement (LA) approved by the Federal Energy Regulatory Commission and under the provisions of the Construction and Coordination Agreement (CCA) entered into by the Path 15 Upgrade Project participants, each participant will receive an allocation of Entitlement and the associated Transmission System Rights in the Project proportional to each party's contribution to the Project (save for a specified allocation to Western Area Power Administration – Sierra Nevada Region ("WAPA-SNR") that shall be no less than 10% of the Project). The initial allocation of Entitlements to Trans-Elect NTD Path 15, LLC is as follows:

Allocation	72%
Capacity	1,080 MW (Based on an estimate of 1,500 MW)

The LA and CCA further provide that a final allocation of Entitlements will be determined based on the ratio of the contribution made by Trans-Elect NTD Path 15, LLC to the Project relative to the contributions of other Project participants. Each Path 15 Upgrade Project participant will provide the Coordination Committee and the other Parties with a final accounting of the Project Costs within 180 days after the commencement of the commercial operations to determine the final allocation of Entitlements pursuant to the provisions of the LA and Section 15.4 of the CCA. Trans-Elect NTD Path 15 shall also provide a copy of the final accounting to the ISO. The allocation of Entitlements set forth in this Appendix A is a preliminary estimate of the Entitlements to be granted to Trans-Elect NTD Path 15, LLC and will be amended following a final accounting for the Project, if applicable.

Appendix A
Western Area Power Administration, Sierra Nevada Region
Transmission Rights and Interests

Path 15 Project Facilities

Western is a participant in the Path 15 Upgrade Project, which will consist of a new, single, 83-mile, 500-kilovolt (kV) transmission line and associated substation facilities extending between the PG&E Los Banos Substation in the California Central Valley (the northern terminus of the Project) and the Gates Substation (the southern terminus of the Project), including modifications at the substations to connect the line as well as reconfigurations to the Gates – Midway 230-kV line and the 115 kV line north of Midway. Voltage support facilities will also be added at the Los Banos and Gates Substations as part of the Project. Western will own the portion of the Path 15 Project Facilities consisting of the 500 kV transmission line between the Los Banos and Gates Substations.

Under the terms of the Letter Agreement (LA) approved by the Federal Energy Regulatory Commission and under the provisions of the Construction and Coordination Agreement (CCA) entered into by the Path 15 Upgrade Project participants, each participant will receive an allocation of "Transmission System Rights" in the Project. Western's allocation of Transmission System Rights under the LA and CCA is as follows:

Allocation	10%
Capacity	150 MW (Based on an estimate of 1,500 MW)

Western is turning over to ISO Operational Control all of its rights and interests in both its ownership of the Project facilities and its contract Transmission System Rights.

APPENDIX A: CITY OF PASADENA
TRANSMISSION ENTITLEMENTS

Ref	Point of Receipt-Delivery (see note 2)	Parties	Direction	Contract Title	FERC No.	Contract Termination	Contract Amount
B1.	IPP - Adelanto Switching Station	Pasadena-SCPPA	Bi-directional	Southern Transmission System Transmission Service Contract		15-Jun-27	113 MW
B2.	Mead - Marketplace - Adelanto	Pasadena-SCPPA	Bi-directional	Mead-Adelanto Project Transmission Service Contract		31-Oct-30	75 MW
B3.a	Westwing – Mead 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	33 MW
B3.b	Mead 500 kV - Marketplace 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	60 MW
B3.c	Mead 500 kV - Mead 230 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix Project Transmission Service Contract		31-Oct-30	25 MW
B4.	Marketplace 500 - McCullough 500 kV	Pasadena-SCPPA	Bi-directional	Mead-Phoenix and Mead-Adelanto Project Transmission Service Contracts		31-Oct-30	135 MW
B5.	Adelanto - Victorville	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
B6.a	IPP - Mona Substation	Pasadena-LADWP - Utah Participants	Bi-directional	IPP Excess Power Sales Sales Agreement		15-Jun-27	104 MW [Note 3]
B6.b	IPP - Gonder Substation	Pasadena-LADWP - Utah Participants	Bi-directional	IPP Excess Power Sales Sales Agreement		15-Jun-27	16 MW [Note 3]
B7.	Sylmar – T.M. Goodrich	Pasadena-SCE	Bi-directional	230-KV Interconnection and Transmission Agreement		04-Aug-10	200 MW
B8.a	Adelanto - Sylmar	Pasadena-LADWP	Bi-directional	IPP Transmission Service Agreement 14443		15-Jun-27	110 MW [Note 2]
B8.b	Adelanto - Sylmar	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW [Note 2]
B9.	Victorville – Sylmar	Pasadena-LADWP	Bi-directional	Victorville-Sylmar Transmission Service Agreement 14444		Note 1	26 MW [Note 1, Note 2]
B10.	Mead –McCullough	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
B11.	McCullough - Victorville	Pasadena-LADWP	Bi-directional	Hoover Transmission Service Agreement 14442		30-Sep 17	26 MW
C1.	Nevada Oregon Border - Sylmar	Pasadena-LADWP	Bi-directional	Pacific Intertie D-C Transmission Facilities Agreement		14-Apr-41	72 MW [Note 2]
C2.	McCullough – Victorville	Pasadena-LADWP	Bi-directional	McCullough Victorville Line 2 Transmission Agreement 10463		31-May-30	26 MW

Notes

1 This contract is coterminous with the McCullough Victorville Line 2 Transmission Agreement.

2 Deliveries to Sylmar point of delivery are at the SCE/CAISO side of the 230kV bus.

3 The contract amount is subject to change by the terms of the contract.

Appendix A
Trans Bay Cable, LLC
Transmission Entitlements

Trans Bay Cable Project Facilities

Trans Bay Cable LLC (TBC) will develop, finance and construct a high voltage, direct current transmission line of approximately fifty-five miles in length and associated facilities to establish a direct connection between Pacific Gas and Electric Company's (PG&E's) Pittsburg Substation located at a site adjacent to the City of Pittsburg, California in Contra Costa County to PG&E's Potrero Substation within the City of San Francisco (the Project). The transmission line will consist of an approximately 7,000-ton bundled cable consisting of a transmission cable, a fiber optic communications cable and a metallic return. The underwater portion of the transmission line will be laid by a ship or barge with special equipment in a single trench underneath San Francisco Bay. The remaining length of the transmission line (most likely a few hundred yards at either end of the line) will be buried underground, either through directional drilling or laid in a trench. In addition, the Project will involve the construction of two converter stations near each of the PG&E Substations to convert the alternating current received at the Pittsburg Substation to direct current and then back to alternating current at the Potrero Substation.

TBC will provide the funding for (i) the development and construction of the Project, (ii) the acquisition of all needed real property and other interests and (iii) the reimbursement of the on-going operation and maintenance expenses of the Project. In return and pursuant to the Operating Memorandum among TBC, the City of Pittsburg and Pittsburg Power Company which was accepted for filing by the Federal Energy Regulatory Commission (112 FERC ¶ 61,095, *order granting clarification,* 114 FERC ¶ 61,031), TBC will be granted 100% of the Entitlements to the transmission capacity created by the Project and all financial benefits associated with the Entitlements. In accordance with the TCA and the TO Tariff, TBC will transfer the Entitlements created by the Project to ISO Operational Control at the time the Project enters service.

APPENDIX A: STARTRANS IO, L.L.C.

TRANSMISSION ENTITLEMENTS

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
1. Mead-Adelanto Project (MAP)	SCPPA, MSR, Startrans IO (Operating Agent-LA)	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, Startrans IO, SRP, APR (Operating Managers – SRP, Western (DSW))		- 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				28 MW 47 MW 75 MW

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)[10]

(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.	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.	

[10] 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.

5.	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	
6.	Midway-Sunset Co-Generation	Cogeneration Project Special Facilities – PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
7.	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
8.	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
9.	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	
10.	Path 15 Operating Instructions Settlement, Revision 1 – Various, see FERC Docket No. ER04-61-000	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.	Upon request by PG&E after 1/1/05, subject to FERC acceptance.	
11.	Power Exchange	Control Area Transmission Service Agreement – PG&E Rate Schedule FERC No. 186	Transmission and various other services	Terminated 3/1/2000. PG&E filing of FERC termination pending submittal	
12.	Puget Sound Power & Light	Capacity and Energy Exchange – PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates on 5 years' advance notice.	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
13.	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
14.	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	
15.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement – PG&E Rate Schedule FERC No. 38	Transmission service	8/1/2007	Both entitlement and encumbrance.
16.	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 classified as an entitlement since loop flow is reduced or an encumbrance if PG&E isasked to cut.
17.	Shelter Cove	Interconnection Agreement – PG&E Rate Schedule FERC No. 198	Distribution	6/30/2006	Effective 8/15/96
18.	Sierra Pacific	Interconnection Agreement – PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
19.	SMUD	Interconnection Agreement – PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
20.	SMUD	EHV Transmission Agreement – PG&E Rate Schedule FERC No. 37	Transmission	Terminated 1/1/2005 (appeal pending)	
21.	SMUD	Camp Far West Transmission Agreement – PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
22.	SMUD	Slab Creek Transmission Agreement – PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	
23.	TANC and other COTP Participants, and WAPA	Owners Coordinated Operations Agreement – PG&E Rate Schedule FERC No. 229	Transmission system coordination, curtailment sharing, rights allocation, scheduling.	1/1/2043, or on two years' notice, or earlier if other agreements terminate	Both entitlement and encumbrance
24.	TANC and other COTP Participants	COTP Interconnection Rate Schedule – PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	
25.	TANC	Midway Transmission Service / South of Tesla Principles – PGE& Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation,* replacement power	Same as the COTP Interim Participation Agreement, subject to exception	
26.	Turlock Irrigation District	Interconnection Agreement – PG&E Rate Schedule FERC No. 213	Interconnection, transmission	4/1/2008, subject to exception	
27.	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
28.	WAPA	San Luis Unit – Contract No. 2207A – PG&E Rate Schedule FERC No. 227 (superseding Original Tariff Sheet Nos. 104 through 137 of PG&E Rate Schedule FERC No. 79)	Transmission	4/1/2016	

* 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
29.	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

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 of the date hereof (the "PG&E Mortgage"). The transfer of Operation 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 require to consummate the transfer of Operation Control to the ISO pursuant to this Agreement.

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

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

Purpose and Objective

Path 15 Curtailment Instructions provide direction to the ISO regarding the management of congestion on Path 15 and are submitted to the ISO, as part of the Transmission Rights and Transmission Curtailment (TRTC) Instructions, by PG&E as the Responsible PTO for the Existing Transmission Contract (ETC) rights on the path.

These instructions are to be administered and adhered to by the ISO 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.

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 - 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
3.	Devers-- Vista	Colton	To Vista	1995 San Juan Unit 3 Firm Transmission Service Agreement	365	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
4.	Hinds - Vincent	MWD	Bi-dir.	District-Edison 1987 Service and Interchange Agreement	443	The earlier of either (1) the term of MWD's Hoover Electric Service Contract (DE-MS65-86WP39583) expected to be 9/30/2017 or (2) five-year notice	110 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
5.	Eldorado-Vincent	CDWR	Bi-dir.	Firm Transmission Service Agreement (Eldorado-Vincent)	113	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
6.	Eldorado / Mohave - Lugo	LADWP	Bi-dir.	Victorville - Lugo Interconnection Agreement	51	11/20/ 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.
7.	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.
8.	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
9.	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.
10.	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.
11.	Mead - ISO Grid Take Out Point serving Banning	Banning	E-W	Hoover Firm Transmission Service Agreement	378	Earliest of: Banning's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	2 MW
12.	Mead - Rio Hondo	Azusa	Bi-dir	Sylmar Firm Transmission Service Agreement	375	Earliest of: Azusa's 1-year notice given after 1/1/02, or termination of Azusa's interest in San Juan #3	8 MW
13.	Mead - Rio Hondo	Azusa	E-W	Hoover Firm Transmission Service Agreement	372	Earliest of: Azusa's 1-year notice given after 1/1/02, or termination of WAPA Service Contract	4 MW
14.	Mead - Vista	Colton	E-W	Hoover Firm Transmission Service Agreement	361	Earliest of: Colton's 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
15.	Mead - Riverside	Riverside	E-W	Hoover Firm Transmission Service Agreement	390	180 day notice by Riverside or termination of WAPA Service Contract	30 MW
16.	Mead - Laguna Bell	Vernon	Bi-dir	Mead Firm Transmission Service Agreement	207	Upon mutual agreement or termination of Hoover Power Sales Agreement	26 MW
17.	Mead - Mountain Center	AEPCO	E-W	Firm Transmission Service Agreement	131	7/1/21 or on 10 years notice	10 MW
18.	Palo Verde - Devers	LADWP	Bi-dir	Exchange Agreement	219	Earliest of (i) in-service of DPV#2 line, (ii) the in-service date of any other new transmission line connecting Palo Verde to Devers in which LADWP has obtained an ownership interest or entitlement, (iii) the date DPV#1 is permanently removed from service, (iv) 4 years after CPUC approval to transfer DPV#2 rights of way to LADWP or (v) 12 months notice by LADWP.	368 MW
19.	Palo Verde - Sylmar	LADWP	Bi-dir.	Exchange Agreement	219	5/31/2012	100 MW
20.	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
21.	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.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
22.	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
23.	Midway - SONGS	SDG&E	N-S	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20-SDG&E)	7/31/07	161 MW
24.	Midway - Vincent 500 kV	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW
25.	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
26.	Midway - SONGS	SDG&E	S-N	California Companies Pacific Intertie Agreement	40 (38- PG&E; 20- SDG&E)	7/31/07	109 MW
27.	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
28.	Pacific AC 500 kV Intertie	LADWP	Bi-dir.	Exchange Agreement	219	5/31/25 or Pacific AC Intertie Agreement termination on 7-31-2007	320 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
29.	SONGS - Vista	Riverside	To Vista	SONGS 2 & 3 Firm Transmission Service Agreement	393	180 day notice by Riverside or SONGS Participation termination	42 MW
30.	Victorville/Lugo - Midway	MSR	S-N	Firm Transmission Service Agreement (Victorville/Lugo-Midway)	339	Earlier of: five-year notice by MSR, or life of Mead-Adelanto 500 kV Transmission Project	150 MW
31.	Victorville/Lugo - Vista	Riverside	To Vista	Intermountain Power Project Firm Transmission Service Agreement	391	180 day notice by Riverside or IPP Participation termination	156 MW
32.	Victorville/Lugo - Rio Hondo	Azusa	To Rio Hondo	PVNGS Firm Transmission Service Agreement	373	Earliest of: Azusa's 1-year notice given after 1/1/02, termination of PVNGS entitlement, or termination of PVNGS participation.	4 MW
33.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	To Banning	PVNGS Firm Transmission Service Agreement	379	Earliest of: Banning's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	3 MW
34.	Victorville/Lugo - Vista	Colton	To Vista	PVNGS Firm Transmission Service Agreement	362	Earliest of: 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
35.	Victorville/Lugo - Vista	Riverside	To Vista	PVNGS Firm Transmission Service Agreement	392	Earliest of: Riverside's 1-year notice given after 1/1/02, or termination of PVNGS entitlement, or termination of PVNGS participation.	12 MW
36.	Victorville/Lugo -–Laguna Bell	Vernon	Bi-dir.	Victorville-Lugo Firm Transmission Service	360	Terminates with permanent removal of Mead-Adelanto from service	11 MW
37.	Victorville/Lugo - ISO Grid Take Out Point serving Banning	Banning	Bi-dir.	Sylmar Firm Transmission Service Agreement	380	Earliest of 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
38.	Victorville/Lugo - Rio Hondo	Azusa	to Rio Hondo	Pasadena FTS	374	Earliest of Azusa's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	14 MW
39.	Victorville/Lugo - Vista	Colton	to Vista	Pasadena FTS	363	Earliest of Colton's 1-year notice given after 1/1/02, or termination of ownership in San Juan #3.	18 MW
40.	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	10 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
41.	Sylmar - Goodrich	Pasadena	Bi-dir	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
42.	Sylmar - Vista	Colton	Bi-dir.	Sylmar Firm Transmission Service Agreement	364	Earliest of: Colton's 1-year notice given after 1/1/02, or termination of Idaho service contract.	3 MW
43.	Sylmar - Midway	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Termination of Vernon COTP Ownership	93 MW until 1/1/00, 93MW after 12/31/07
44.	Sylmar - Laguna Bell	Vernon	Bi-dir.	Edison-Vernon Firm Transmission Service Agreement	272	Termination of Vernon COTP Ownership	60 MW
45.	Sylmar - SONGS	SDG&E	To SDG&E	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	100 MW
46.	Sylmar - SONGS	SDG&E	To Sylmar	California Companies Pacific Intertie Agreement	40 (38-PG&E; 20-SDG&E)	7/31/07	105 MW
47.	Sylmar - Mead	PG&E	To Mead.	Edison-PG&E Transmission Agreement	256	7/31/07	Up to 200 MW of FTS.

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
48.	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.
49.	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
50.	Mojave Siphon (Vista) - Vincent	CDWR	To Vincent	CDWR Mojave Siphon Additional Facilities and Firm Transmission Service Agreement	342	Life of Plant	28 MW

	POINT OF RECEIPT-DELIVERY	PARTIES	DIR.	CONTRACT TITLE	FERC No.	CONTRACT TERMINATION	CONTRACT AMOUNT
51.	Blythe - Cibola, & Ehrenberg	APS	To APS Load	Firm Transmission Service (Blythe Accounts)	348	Upon 3-year notice by APS, or 10 year notice by Edison	Presently 5.1 MW, 7 MW max.

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 (3 lines) - Talega (2 lines)
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 – 76.22%; IID – 12.78%.**
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.**

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

POINT OF RECEIPT-DELIVERY	PARTIES	DIRECTION	CONTRACT-TITLE	FERC	CONTRACT TERMINATION	CONTRACT AMOUNT
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

APPENDIX B: CITY OF PASADENA
ENCUMBRANCES

	Point of Receipt-Delivery	Parties	Direction	Contract Title	FERC No.	Contract Start Date	Contract Termination	Contract Amount
1.	Nevada/Oregon Border – Sylmar	Pasadena - Riverside, Azusa, Banning, Colton	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		01-Oct-89	30-Sep-09	14 MW
2.	Nevada/Oregon Border - Sylmar	Pasadena - Anaheim	Bi-directional	Pacific Intertie Direct Current Firm Transmission Service Agreement		01-Oct-89	30-Sep-09	10 MW

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO TRANSMISSION MAINTENANCE STANDARDS

TABLE OF CONTENTS

1. DEFINITIONS[1]

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

Availability Measures - Within each Voltage Class in a calendar year: 1) the average Forced Outage(IMS) frequency for all Transmission Line Circuits, 2) the average accumulated Forced Outage(IMS) duration for only those Transmission Line Circuits with Forced Outages(IMS), and 3) the proportion of Transmission Line Circuits with no Forced Outages(IMS).

Availability Measure Targets - The Availability performance goals jointly established by the ISO and a PTO for that PTO's Transmission Facilities.

Forced Outage(IMS) – An event that occurs when a Transmission Facility is in an Outage(IMS) condition for which there is no Scheduled Outage(IMS) request in effect.

ISO Transmission Maintenance Standards - The Maintenance standards set forth in this Appendix C.

Maintenance - Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities performed with respect to Transmission Facilities.

Maintenance Practices - A confidential description of methods used by a PTO, and adopted by the ISO, for the Maintenance of that PTO's Transmission Facilities.

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

Maintenance Procedures – Documents developed by the Transmission Maintenance Coordination Committee for use by the ISO and the PTOs to facilitate compliance with the ISO Transmission Maintenance Standards. These documents shall serve as guidelines only.

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

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

Scheduled Outage$^{(IMS)}$ - The removal from service of Transmission Facilities in accordance with the requirements of Section 7.1 of the Transmission Control Agreement and the applicable provisions of the ISO Tariff and ISO Protocols.

Station – Type of Transmission Facility used for such purposes as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities - All equipment and components transferred by a PTO to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and associated facilities.

Transmission Line Circuit - The continuous set of transmission conductors, under the ISO Operational Control, 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.

Transmission Maintenance Coordination Committee ("TMCC") - The committee described in Section 7 of this Appendix C.

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

Capitalized terms, not expressly defined above, are used consistently with the definitions provided in the Transmission Control Agreement and the ISO Tariff.

2. INTRODUCTION

This Appendix C delineates the ISO Transmission Maintenance Standards and has been developed through a lengthy consensus building effort involving initially the ISO Maintenance Standards Task Force, and currently the TMCC.

Flexibility in establishing these ISO Transmission 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, each PTO will prepare its own Maintenance Practices that shall be consistent with the requirements of these ISO Transmission Maintenance Standards. The effectiveness of each PTO's Maintenance Practices will be gauged through the Availability performance monitoring system. Each PTO's adherence to its Maintenance Practices will be assessed through an ISO review.

In developing these ISO Transmission Maintenance Standards, both the ISO Maintenance Standards Task Force and TMCC determined that it is impractical to develop and/or impose on the PTOs a single uniform set of prescriptive practices delineating conditions or time-based schedules for various Maintenance activities that account for the myriad of equipment, operating conditions, and environmental conditions within the ISO Controlled Grid. For this reason, these ISO Transmission Maintenance Standards provide requirements for the PTOs in preparing their respective Maintenance Practices.

2.1. OBJECTIVE

This Appendix C provides for a high quality, safe, and reliable ISO Controlled Grid by meeting the following objectives:

- Ensuring that the Availability performance levels inherent to the Transmission Facilities are maintained,
- Restoring Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Economically extending the useful life of the Transmission Facilities while maintaining inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum reasonable total cost for Maintenance with the intent of minimizing customer impacts.

2.2. AVAILABILITY

ISO Controlled Grid reliability is a function of a complex set of variables, including accessibility of alternative paths to serve Load, Generating Unit availability, Load forecasting and resource planning; speed, sophistication and coordination of protection systems; and the Availability of Transmission Line

Circuits owned by the PTOs. Availability Measures have been chosen as the principal determinant of each PTO's Maintenance effectiveness.

When using Availability Measures as a general gauge of Maintenance effectiveness, several things must be considered to avoid misinterpreting performance. Availability is a function of several variables, including Transmission Facility Maintenance, initial design, extreme exposure, capital improvements, and improvements in restoration practices. These factors should be taken into account when assessing Availability Measures and Maintenance effectiveness. It is important to consider that Maintenance is one of many variables that impact changes in Availability. For example, certain Forced Outages(IMS) that impact Availability may be due to events that generally cannot be controlled by Maintenance.

If Availability Measures are either improving or declining, it is important to investigate the cause(s) and any trends that are causing change before drawing conclusions. If Maintenance is being performed by a PTO consistent with Good Utility Practice, increasing Maintenance activities by a significant order may not result in a corresponding increase in Availability and if Maintenance is not performed consistent with Good Utility Practice, Availability may decline. Thus, while Maintenance is important to ensure Availability, unless a PTO fails to perform Maintenance on a basis consistent with Good Utility Practice, significant increases in Maintenance activities will generally not lead to substantial improvements in Availability and associated ISO Controlled Grid reliability.

A variety of techniques can be used to monitor Maintenance effectiveness. 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 Maintenance effectiveness. To account for random/chance variations while enabling monitoring for shifts and trends, control charts have been widely accepted and utilized. 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 Maintenance effectiveness.

To enhance the use of Availability Measures as a gauge of Maintenance effectiveness, it is necessary to exclude certain types of Outages(IMS). These excluded Outages(IMS), as set forth in more detail in Section 4.1.3 of this Appendix C, are:

- Scheduled Outages(IMS);
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures;
- Forced Outages(IMS) caused by events originating outside the PTO's system; or
- Forced Outages(IMS) demonstrated to have been caused by earthquakes.

Additionally, as described in Section 4.1.2 of this Appendix C, the Forced Outage(IMS) duration used to calculate the Availability control charts 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.

Establishing Availability Measures requires each PTO to use separate control charts for each Voltage Class. Existing Forced Outage(IMS) data contains significant differences in the Availability 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. Regardless of the cause of these differences, review of the Forced Outage(IMS) data makes it eminently apparent that 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 are utilized to provide a complete representation of historical Availability Measures, and to provide a benchmark against which future Availability Measures 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 assist the ISO and PTOs in assessing the Maintenance effectiveness of each Voltage Class over time. To accommodate this process on a cumulative basis, data is made available to the ISO by each PTO at the beginning of each new calendar year to assess past calendar years.

2.3. MAINTENANCE DOCUMENTATION REQUIREMENTS

Two specific requirements regarding Maintenance documentation are incorporated into these ISO Transmission Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance Practices to the ISO. Second, these standards require that each PTO retain Maintenance records as set forth in Section 6.1 of this Appendix C and make those records available to the ISO as set forth in the Maintenance

Procedures, in order to demonstrate compliance with each element of its Maintenance Practices.

2.4. AVAILABILITY DATA STANDARDS

To facilitate processing Forced Outage$^{(IMS)}$ data for the Availability Measures, 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 TMCC has also developed standardized formats for transmitting Forced Outage$^{(IMS)}$ data to the ISO for the Availability Measures. These standard formats are provided in the Maintenance Procedures. To facilitate review of the data by the ISO, the TMCC has developed a standard Availability Measures reporting system detailed in the Maintenance Procedures and in Section 4 of this Appendix C. This system will provide for consistent gathering of information that can be used as the basis for analyzing Availability Measures trends.

3. FACILITIES COVERED BY THESE ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO Transmission Maintenance Standards set forth in this Appendix C shall apply to all Transmission Facilities. Each PTO shall maintain its Transmission Facilities in accordance with its Maintenance Practices as adopted by the ISO in accordance with these ISO Transmission Maintenance Standards.

4. AVAILABILITY MEASURES

4.1. CALCULATION OF AVAILABILITY MEASURES FOR INDIVIDUAL TRANSMISSION LINE CIRCUITS

4.1.1 FREQUENCY AND DURATION

The calculation of the Availability Measures will be performed utilizing Forced Outage(IMS) data through December 31st of each calendar 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 Forced Outage(IMS) data for the calendar year in question.

Forced Outage(IMS) Frequency:

The Forced Outage(IMS) frequency (f_{ik}) of the i^{th} Transmission Line Circuit shall equal the total number of Forced Outages(IMS) that occurred on the i^{th} 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 calendar 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 calendar year, i.e., the Forced 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 "jth" Forced Outage(IMS) which occurred during the "kth" calendar year for the "ith" Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages(IMS) shall be capped as described in Section 4.1.2 of this Appendix C for the purposes of calculating the Availability Measures. In addition, certain types of Outages(IMS) shall be excluded from the calculations of the Availability Measures as described in Section 4.1.3 of this Appendix C.

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Forced 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 if and how the Availability Measures and Availability Measure Targets should be modified to ensure that they (1) remain consistent with the modified Transmission Line Circuit identification or Forced

Outage(IMS) data reporting scheme, and (2) provide an appropriate gauge of Availability.

4.1.2. CAPPING FORCED OUTAGE(IMS) DURATIONS

The duration of each Forced Outage(IMS) which exceeds 72 hours (4320 minutes) shall be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage(IMS) duration.

4.1.3. EXCLUDED OUTAGES (IMS)

The following types of Outages(IMS) shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- Scheduled Outages(IMS)
- Outages(IMS) classified as "Not a Forced Outage" in the Maintenance Procedures.

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

4.2. AVAILABILITY MEASURE TARGETS

The Availability Measure Targets described herein shall be phased in over a period of five calendar years beginning on the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement. The adequacy of each PTO's Availability Measures shall be monitored through the use of charts. These charts, called control charts as shown in Figure 4.2.1, are defined by a horizontal axis with a scale of calendar 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 Measures for each Voltage Class within each PTO's system:

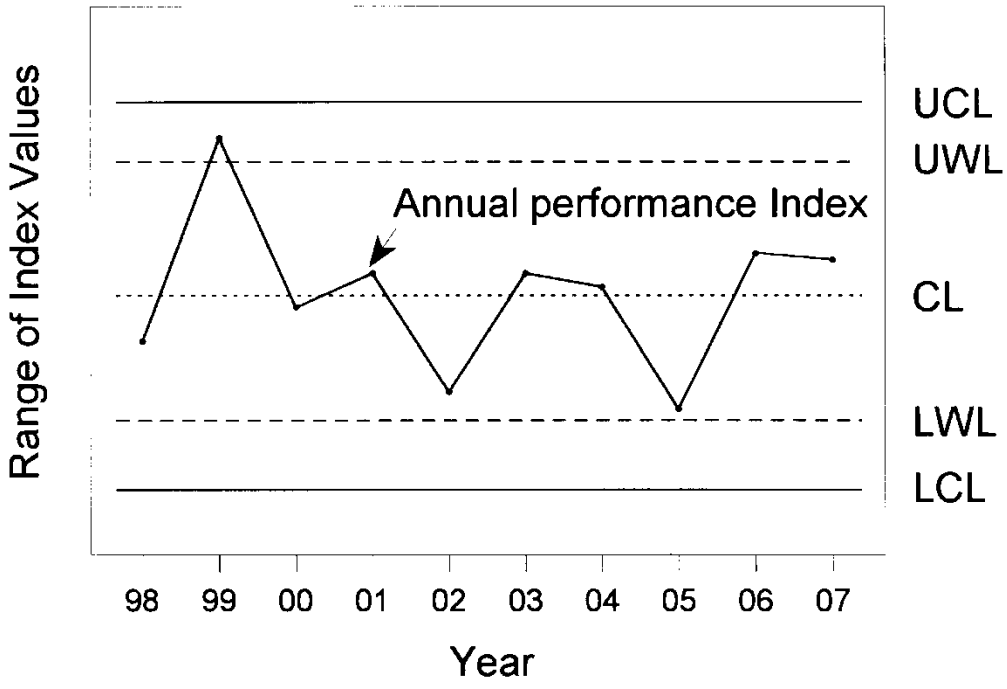

Figure 4.2.1 Sample Control Chart

- 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 control 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 calendar 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 4.2.2 of this Appendix C. 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 its 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 4.2.3 of this Appendix C.

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. The Maintenance Procedures 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 TMCC and approved by the ISO Governing Board for use in creating the control charts.

4.2.1. CALCULATIONS OF ANNUAL AVAILABILITY MEASURES INDICES FOR INDIVIDUAL VOLTAGE CLASSES

Separate annual Availability Measures indices shall be calculated for each Voltage Class and each PTO as described below by utilizing the calculations discussed in Section 4.1 of this Appendix C.

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 4.1.1 of this Appendix C.

f_{ik} = frequency of Forced Outages(IMS) for the "ith" Transmission Line Circuit as calculated in accordance with Section 4.1.1 of this Appendix C 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 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

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 4.1.1 of this Appendix C.

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 4.1.1 of this Appendix C.

$N_{o,k}$ = 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 4.1.1 of this Appendix C is greater than zero for the calendar year "k". See Note 2, Section 4.1.1 of this Appendix C.

4.2.2. DEVELOPMENT OF LIMITS FOR 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 those Transmission Line Circuits with Forced Outages$^{(IMS)}$; and Annual Proportion of Transmission Line Circuits with No Forced Outages$^{(IMS)}$) on which the annual Availability Measures 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 Forced Outage$^{(IMS)}$ data for the ten calendar year period immediately preceding the date a Transmission Owner becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

In the event that a PTO does not have reliable, continuously recorded Forced Outage$^{(IMS)}$ data for this 10 calendar year period, that PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, that PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO within 90 days after the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement.

The ISO shall periodically review the control chart limits and recommend appropriate modifications to each PTO in accordance with this Appendix C.

4.2.2.1. CENTER CONTROL LINES (CLs)

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability Measures indices described in Section 4.2.1 of this Appendix C except that the time period is expanded from a single calendar year to ten calendar years, unless a shorter period is justified by a PTO, for the period preceding the date a TO becomes a PTO in accordance with the provisions of the Transmission Control Agreement. 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 Average 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*" calendar years prior to the date a TO becomes a PTO.

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

CL for Annual Average 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*" calendar years prior to 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*" calendar years prior to the date a TO becomes a PTO.

4.2.2.2. 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 Calendar 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 calendar year's 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 Transmission Line Circuits per calendar 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 database. 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 database, 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 ten 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 Transmission Line Circuits 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 calendar year with a history of ten calendar years. Furthermore, assume that about 15 Transmission Line Circuits per calendar year experience Forced Outages$^{(IMS)}$. 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 Transmission Line Circuits over the ten calendar years using the formulas in Section 4.2.2.1 of this Appendix C. 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 calendar year in a Voltage Class for fewer than five calendar 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 calendar years. For example, if a Voltage Class has only two Transmission Line Circuits per calendar year for five calendar years, the data base will consist of 2*5 = 10 accumulated Forced Outage$^{(IMS)}$ durations assuming both Transmission Line Circuits experience one Forced Outage$^{(IMS)}$ or more per calendar year. Resampling two values from the column of ten 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 database. If n is the median number of Transmission Line Circuits per calendar 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).

UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Transmission Line Circuits is > 125

According to standard procedures for proportion control charts for Voltage Classes where the median number of Transmission Line Circuits in service is greater than 125 for any given calendar year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the "kth" calendar 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 "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*" calendar years prior to 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 Transmission Line Circuits 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 Line Circuits per calendar 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 contain about 99.5% and the UWL and LWL contain 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:

$$\mathbf{UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

$$\mathbf{LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/ n}$$

Where

P_1 = A cumulative binomial probability that if not equal to the P_2 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 = 0.99529 and is closest to the 99.75 percentile value, from the low side, P_1 = 0.99529 should be used in the UCL formula).

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 (e.g., P_2 = 0.9975 in the UCL formula and = 0.025 in the LWL formula).

P_3 = A cumulative binomial probability that if not equal to the P_2 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 = 0.99796 and is closest to the 99.75 percentile value, from the high side, then P_3 = 0.99796 should be used in the UCL formula).

X_1 = The number of Transmission Line Circuits with no Forced Outages$^{(IMS)}$ associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g., if P_1 = 0.99529 and represents the closest percentile from below the 99.75 percentile for the case where 19 Transmission Line Circuits had no Forced Outages$^{(IMS)}$, then X_1 = 19 should be used in the UCL formula).

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

4.2.3. EVALUATION OF AVAILABILITY MEASURES PERFORMANCE

The control charts shall be reviewed annually by the ISO and PTOs in order to evaluate Availability Measures performance. The annual 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 calendar year, shifts in longer-term performance, and trends in longer-term performance.

Tests

- **Test 1:** The index value for the current calendar 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 Table indicates 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 calendar years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three calendar 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 indicate 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 4.2.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last calendar 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 calendar year's data.

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

For the special case where only one Transmission Line Circuit has a Forced Outage$^{(IMS)}$ in a Voltage Class during a calendar 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 calendar 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 used in creating the control charts

Table 4.2.1 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		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Average Accumulated Forced Outage(IMS) Duration	1	value is above the UCL		X
		value is below the LCL when LCL>0	X	
	2	v1 or more consecutive values above the CL		X
		v2 or more consecutive values below the CL	X	
	3	2 out of 3 values above the UWL		X
		2 out of 3 values below the LWL	X	
	4	6 consecutive values increasing		X
		6 consecutive values decreasing	X	
Annual Proportion of Transmission Line Circuits with No Forced Outages(IMS)	1	value is above the UCL	X	
		value is below the LCL when LCL>0		X
	2	v1 or more consecutive values above the CL	X	
		v2 or more consecutive values below the CL		X
	3	2 out of 3 values above the UWL	X	
		2 out of 3 values below the LWL		X
	4	6 consecutively increasing values	X	
		6 consecutively decreasing values		X

4.3. AVAILABILITY REPORTING

Each PTO shall submit an annual report to the ISO within 90 days after the end of each calendar year describing its Availability Measures performance. This annual report shall be based on Forced Outage(IMS) records. All Forced Outage(IMS) records shall be submitted by each PTO to the ISO and shall include the date, start time, end time, affected Transmission Facility, and the probable cause(s) if known.

5. MAINTENANCE PRACTICES

5.1. INTRODUCTION

These ISO Transmission Maintenance Standards, as they may be periodically revised in accordance with the provisions of the Transmission Control Agreement and this Appendix C, and as they may be clarified by the Maintenance Procedures, shall be followed by each PTO in preparing, submitting, and amending its Maintenance Practices. The Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including facility importance.

5.2. PREPARATION OF MAINTENANCE PRACTICES

5.2.1. TRANSMISSION LINE CIRCUIT MAINTENANCE

As may be appropriate for the specific Transmission Line Circuits under the ISO's Operational Control, each PTO's Maintenance Practices shall describe the Maintenance activities for the various attributes listed below:

5.2.1.1. OVERHEAD TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Conductor and shield wire
- Disconnects/pole-top switches
- Structure grounds

- Guys/anchors
- Insulators
- Rights-of-way
- Structures/Foundations
- Vegetation Management

5.2.1.2. UNDERGROUND TRANSMISSION LINES

- Patrols and inspections, scheduled and unscheduled
- Cable/Cable systems
- Cathodic Protection
- Fluid pumping facilities
- Terminations
- Arrestors
- Rights-of-way
- Splices
- Structures/vaults/manholes
- Vegetation Management

5.2.2. STATION MAINTENANCE

As may be appropriate for the specific Stations under the ISO's Operational Control, each PTO's Maintenance Practices shall describe Maintenance activities for the various attributes listed below:

- Inspections, scheduled and unscheduled
- Battery systems
- Circuit breakers
- Direct Current transmission components
- Disconnect switches
- Perimeter fences and gates
- Station grounds
- Insulators/bushings/arrestors
- Reactive power components
- Protective relay systems
- Station Service equipment
- Structures/Foundations
- Transformers/regulators
- Vegetation Management

5.2.3. DESCRIPTIONS OF 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 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 Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility. Where appropriate, the 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 Facility.

5.3. REVIEW AND ADOPTION OF MAINTENANCE PRACTICES

5.3.1. INITIAL ADOPTION OF MAINTENANCE PRACTICES

In conjunction with its application to become a PTO, each prospective PTO shall provide to the ISO its proposed Maintenance Practices which comply with the requirements set forth in this Appendix C and Section 14.1 of the Transmission Control Agreement. This information shall provide sufficient detail for the ISO to assess the proposed Maintenance Practices.

The ISO shall review the proposed Maintenance Practices and may provide recommendations for an amendment. To the extent there is any disagreement between the ISO and the prospective PTO regarding the prospective PTO's proposed Maintenance Practices, such disagreement shall be resolved by the ISO and prospective PTO so that the ISO and the prospective PTO will have adopted Maintenance Practices, consistent with the requirements of this Appendix C and the Transmission Control Agreement, for the prospective PTO at

the time that the ISO assumes Operational Control of the prospective PTO's Transmission Facilities. To the extent there are no recommendations, the proposed Maintenance Practices will be adopted by the ISO and the prospective PTO as the Maintenance Practices for that prospective PTO.

5.3.2. AMENDMENTS TO THE MAINTENANCE PRACTICES

5.3.2.1. AMENDMENTS PROPOSED BY THE ISO

Each PTO shall have in place Maintenance Practices that have been adopted by the ISO as set forth in this Appendix C. The ISO shall periodically review each PTO's Maintenance Practices having regard to these ISO Transmission Maintenance Standards and Maintenance Procedures. Following such a review, the ISO may recommend an amendment to any PTO's Maintenance Practices by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The PTO may draft amended language in response to the ISO's recommendation. If the PTO exercises its option to draft amended language to the ISO's proposed amendment, the PTO shall so notify the ISO within 30 days after the receipt of notice from the ISO. The PTO will provide the ISO with its proposed amendment language in a time frame mutually agreed upon between the PTO and the ISO. If, after the ISO receives the proposed amendment language from the PTO, the ISO and the PTO are unable to agree on the language implementing the ISO recommendation, then the provisions of Section 5.3.3.2 of this Appendix C shall apply.

5.3.2.2. AMENDMENTS PROPOSED BY A PTO

Each PTO may provide to the ISO its own recommendation for an amendment to its own Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement.

5.3.3. DISPOSITION OF RECOMMENDATIONS

5.3.3.1. If the ISO makes a recommendation to amend the Maintenance Practices of a PTO, as contemplated in Section 5.3.2.1 of this Appendix C, that PTO shall have 30 Business Days to provide a notice to the ISO, pursuant to Section 26.1 of the Transmission Control Agreement, stating that it does not agree with the recommended amendment or that it intends to draft the language implementing the amendment, as set forth in Section 5.3.2.1 of this Appendix C. If the PTO does not provide such a notice, the amendment recommended by the ISO shall be deemed adopted.

If a PTO makes a recommendation to amend its own Maintenance Practices, as contemplated in Section 5.3.2.2 of this Appendix C, the ISO shall have 30 Business Days to provide a notice to that PTO, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not concur with the recommended amendment. If the ISO does not provide such a notice, then the recommended amendment shall be deemed adopted. Notwithstanding the foregoing, if an amendment proposed by a PTO to its own Maintenance Practices meets the objectives of Section 2.1 of this Appendix C and is submitted in accordance with the requirements in Section 5.2 of this Appendix C, the ISO shall adopt said amendment.

If any amendment to a PTO's Maintenance Practices is adopted, the PTO will specify the transition time to implement the adopted amendment so as to ensure the ISO and PTO are clear as to the implementation time frame where Maintenance may be performed under both sets of practices.

5.3.3.2. If the ISO or a PTO makes a recommendation to amend Maintenance Practices and if the ISO or PTO provides notice within the 30 Business Days specified in Section 5.3.3.1 of this Appendix C that the ISO or PTO 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 Maintenance Practices shall remain in effect. Either Party may, however, seek further redress through appropriate processes, including non-binding discussions at the TMCC 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. Following the conclusion of any and all redress processes, the PTO's Maintenance Practices, as modified, if at all, by these processes, shall be deemed adopted by the ISO, as the Maintenance Practices for that PTO, pursuant to the implementation time frame agreed to between the PTO and the ISO.

5.3.3.3. If the ISO determines, that prompt action is required to avoid a substantial risk to reliability of the ISO Controlled Grid, it may direct a PTO to implement certain temporary Maintenance activities in a period of less than 30 Business 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 advisory issued pursuant to this Section 5.3.3.3 shall specify why implementation solely under Sections 5.3.3.1 and 5.3.3.2 of this Appendix C is not sufficient to avoid a substantial risk to reliability of the ISO Controlled Grid, including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. The ISO shall consult with the relevant PTO before issuing a Maintenance 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 Maintenance advisories shall cease to have effect 90 Business Days after issuance by the ISO or on such earlier date as the ISO provides in its notice.

Any Maintenance advisories required to remain in effect beyond 90 Business Days shall require a recommendation process pursuant to Section 5.3.3.1 or Section 5.3.3.2 of this Appendix C.

5.4. QUALIFICATIONS OF PERSONNEL

All Maintenance of Transmission Facilities 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

A PTO shall maintain and provide to the ISO records of its Maintenance activities in accordance with this Section 6 of this Appendix C.

6.1. PTO MAINTENANCE RECORD KEEPING

The minimum record retention period for Transmission Facilities subject to time based scheduled intervals shall be the designated Maintenance cycle plus two years. The minimum record retention period for all other Transmission Facility Maintenance activities identified through inspection, assessment, diagnostic or another process shall be a minimum of 2 years after the date completed.

A PTO's Maintenance records shall, at a minimum, include the: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any); and 6) description of Maintenance activity performed.

6.2. PTO MAINTENANCE REPORTING

Each PTO will submit a Standardized Maintenance Report as outlined in the Maintenance Procedures. The ISO will accept, at the PTO's option, a Standardized Maintenance Report in either electronic or paper form.

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

Each PTO shall provide to the ISO Maintenance records as described in Section 6.1 and as set forth in the Maintenance Procedures.

6.3. ISO VISIT TO PTO'S TRANSMISSION FACILITIES

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement to determine if the Maintenance Practices are being followed by a PTO.

7. ISO AND TRANSMISSION MAINTENANCE COORDINATION COMMITTEE

The ISO shall establish and convene a Transmission Maintenance Coordination Committee (TMCC). The TMCC shall develop and, if necessary, revise the Maintenance Procedures, including conveying information to and seeking input from PTOs and other interested stakeholders regarding these Maintenance Procedures and any proposed amendments or revision thereto. The TMCC will also make recommendations on the ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will convey information to and seek input from the PTOs and other interested stakeholders on these ISO Transmission Maintenance Standards and any proposed revisions or amendments thereto. The TMCC will also perform any other functions assigned in this Appendix C.

Although the role of the Transmission Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members.

8. REVISION OF ISO TRANSMISSION MAINTENANCE STANDARDS AND MAINTENANCE PROCEDURES

8.1 REVISIONS TO ISO TRANSMISSION MAINTENANCE STANDARDS

The ISO, PTOs, or any interested stakeholder may submit proposals to amend or revise these ISO Transmission Maintenance Standards. All proposals shall be initially submitted to the TMCC for review in accordance with this Appendix C. Any revisions to these ISO Transmission Maintenance Standards shall be made only upon recommendation by the TMCC and only in accordance with the provisions and requirements of the Transmission Control Agreement and this Appendix C.

8.2 REVISIONS TO AND DEVIATIONS FROM MAINTENANCE PROCEDURES

The ISO or any PTO may submit proposals to the TMCC to amend or revise the Maintenance Procedures. Any deviations from the Maintenance Procedures should be held to a minimum and will be negotiated between the ISO and the affected PTO.

9. INCENTIVES AND PENALTIES

9.1 DEVELOPMENT OF A FORMAL PROGRAM

The TMCC shall periodically investigate and report to the ISO on the appropriateness of a formal program of incentives and penalties associated with Availability Measures. Should the TMCC ever recommend that the ISO adopt a formal program of incentive and penalties, the formal program will only be adopted as set forth in Section 9.2 of this Appendix C.

9.2 ADOPTION OF A FORMAL PROGRAM

Any formal program of incentives and penalties adopted by the ISO in connection with matters covered in Section 14 of the Transmission Control Agreement or this Appendix C, shall be established only: 1) with respect to Availability Measures; 2) upon recommendation of the TMCC as set forth in Section 9.1 of this Appendix C; 3) by express incorporation into this Appendix C in accordance with the provisions of the Transmission Control Agreement; and 4) upon approval by the FERC. Nothing in this Appendix C shall be construed as waiving or limiting in any way the right of any party or PTO to oppose or protest any formal program of incentives and penalties filed, proposed or adopted by the ISO and/or FERC or any portion thereof.

9.3 IMPOSITION OF PENALTIES IN THE ABSENCE OF A FORMAL PROGRAM

In the absence of a formal program of incentives and penalties, the ISO may seek FERC permission for the imposition of specific penalties on a PTO on a case-by-case basis in the event that the relevant PTO 1) exhibits significant degradation trends in Availability performance due to Maintenance, or 2) is grossly or willfully negligent with regard to Maintenance.

9.4 NO WAIVER

Nothing in this Appendix C shall be construed as waiving the rights of any PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC, the approval by FERC of any specific penalty or sanction, or the specific imposition by the ISO of any FERC approved penalty or sanction on the PTO.

9.5 LIMITATIONS ON APPLICABILITY TO NEW PTOS

For a new PTO, the Availability Measures system needs to be used and updated during a five calendar year phase in period, as set forth in Section 4.2 of this

Appendix C, to be considered in connection with any formal program of incentives and penalties associated with Availability Measures.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain and the ISO shall operate Transmission Facilities in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable laws and regulations.

10.1 SAFETY

Each PTO shall take proper care to ensure the safety of personnel and the public in performing Maintenance duties. The ISO shall operate Transmission Facilities in a manner compatible with the priority of safety. In the event there is conflict between safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any dispute between the ISO and a PTO relating to matters covered in this Appendix C shall be subject to the provisions of the Transmission Control Agreement, including the dispute resolution provisions set forth therein.

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	Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.
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, 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.

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised as of October 10, 2006

I. OVERVIEW

The preferred source of electrical power for the San Onofre Nuclear Generating Station (SONGS) electrical loads (safety-related and non safety-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 applicable regulatory documents.

The offsite power supply is considered "Operable" with respect to the SONGS Operating License and Technical Specifications when it can provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and mitigate certain specified accident scenarios.

The offsite power supply is considered "Inoperable" with respect to the SONGS Operating License and Technical Specifications if it is degraded to the point that it cannot provide sufficient capacity and capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS.

It is a necessary condition of the SONGS Operating License and Technical Specifications that the offsite power supply be Operable at all times. If the offsite power supply 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.

This level of degradation that would result in inoperability can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable to safely shutdown the units or to supply emergency electrical loads.

Since accident scenarios for which the SONGS plant is designed can result in a unit trip, it is imperative that this trip not impair the operability of the offsite power supply.
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 (see Reference 9 below) 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.

The SONGS switchyard is made up of the Southern California Edison Company (SCE) switchyard and the San Diego Gas & Electric Company (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.

II. REQUIREMENTS

Note: **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 communicated to SCE and the SONGS Control Room for operability determination as soon as practicable, but in any case, within one hour. Changes in the operation of the transmission network that conflict with these requirements must have prior approval by SCE.**

Note: **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 below)

   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 below)

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

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 below)

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

   a. The loss of a SONGS 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 below)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 234 kV. (References 10, 11, 18 below)

6. The normal operating voltage of the SONGS switchyard shall be maintained at 229 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18 below)

7. The 3 limiting conditions for SONGS offsite power supply operability are defined as follows:

   1. One SONGS unit is off- line, and

   2. One of the critical line (s) outages, in GCC Operating Procedure, OP-13: SONGS Voltage (reference 19) occurs, 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 nomograms referenced in the GCC Operating Procedure, OP-13: SONGS Voltage.

   Based on these nomograms and SONGS offline unit's status, whenever limiting conditions 1 and 2, as set forth in this Requirement 7, occur, the ISO (or the SCE Grid Control Center (SCE GCC), as directed by the ISO) shall, as soon as practicable but, in any case, within one hour of the event, perform an evaluation

of system conditions to determine whether or not the SONGS off site power supply remains Operable as defined herein. If the SONGS offsite power supply is Inoperable or cannot be determined to be Operable as defined herein, the ISO (or the SCE GCC, as directed by the ISO) shall notify the SONGS Control Room immediately of entry into the event. Subsequent to notification, the SONGS Control Room shall declare the offsite power supply Inoperable (in anticipation of losing the second SONGS unit) and shall declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period shall be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

In order to ensure the continued ability to meet the 3 limiting conditions identified above in this Requirement 7, the following six requirements (a-f) must be met:

a. Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the offsite power supply Inoperable.

b. Procedures and programs shall be in effect to ensure that the SONGS Control Room is notified as soon as practicable but, in any case, within one hour of an event that renders the offsite power supply Inoperable.

c. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, shall render the offsite power supply Inoperable.

d. 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.

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 formally transmitted to Vice President Nuclear Engineering and Technical Services, San Onofre Nuclear Generating Station. (References 1, 2, 19, and 21 below)

f. System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Electricity Coordinating Council (WECC). (Reference 7 below)

8. In the event of loss of the SONGS offsite power:

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 below)

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 below)

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 shall comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan. (References 7, 20 below)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS Updated Final Safety Analysis Report (UFSAR) 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 below)

11. Patrol and inspection of SCE and SDG&E transmission lines, to ensure that the physical and electrical integrity of transmission components are maintained, shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. (Reference 7 below)

12. Line insulators on lines which carry power from the plant to the grid shall be

washed as required by the SONGS UFSAR 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 below)

13. Maintenance, testing and calibration of SCE and SDG&E station equipment and

protective relays shall be performed as required by the SONGS UFSAR or in accordance with the current ISO approved Electrical Station Maintenance Practice, whichever requirement is more stringent. (Reference 7 below)

14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed in accordance with IEEE 450-1985 or IEEE 450-2002 subsequent to SONGS converting its battery maintenance program to IEEE 450-2002 requirements. (Reference 7, 23 below)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS UFSAR shall be provided annually to facilitate periodic updates to the UFSAR by SONGS that are required by 10CFR50.71(e).

VI REFERENCES (Current approved revision except as noted)

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. 765-2002 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

19) GCC Operating Procedure, OP-013: SONGS Voltage

20) System Operating Bulletin 113, San Onofre 220 kV System Separation

21) Regulatory Guide 1.93, Revision 0, Availability of Electric Power Sources

23) SCE Division Order 60.20, Storage Batteries

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV

28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies

29) IEEE Std, 450-1985 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations

30) IEEE Std. 450-2002 IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

TRANSMISSION CONTROL AGREEMENT

APPENDIX F

NOTICES

NOTICES

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